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# Physical Coal Cleaning for Utility Boiler SO2 Emission Control

Battelle Memorial Inst, Columbus, Ohio Columbus Labs

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Industrial Environmental Research
Laboratory
Research Triangle Park, North Carolina 27711

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# PHYSICAL COAL CLEANING FOR UTILITY BOILER $SO_2$ EMISSION CONTROL

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16. ABSTRACT

The report examines physical coal cleaning as a control technique for sulfur oxides emissions. It includes an analysis of the availability of low-sulfur coal and of coal cleanable to compliance levels for alternate New Source Performance Standards (NSPS). Various alternatives to physical coal cleaning (such as chemical coal cleaning, coal conversion, and fluidized-bed combustion) are also examined with respect to alternate NSPS. Electric power supply and demand through 1985 are reviewed, as well as the technology, cost, and environmental overviews of physical and chemical coal cleaning techniques. Since the report deals with engineering analyses of available data and several technologies in design stages, references are somewhat limited. Descriptions of the methodologies used and the sources of information are given in lieu of referenced published data in many cases.

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| Coal | Coal Gasification | Stationary Sources | 08G, 21D 07A |
| Cleaning | Electric Power Demand | Low-sulfur Coal | 13H |
| Utilities | Electric Power Generation | Coal Conversion | 13A 20C |
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# PHYSICAL COAL CLEANING FOR UTILITY BOILER $SO_2$ EMISSION CONTROL

by

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## ABSTRACT

This study on the use of physical coal cleaning (PCC) for compliance with $SO_2$ emission regulations was part of an evaluation of revised utility boiler New Source Performance Standards (NSPS) performed for EPA's Office of Air Quality Planning and Standards.

Estimates were made of the quantities of naturally occurring low-sulfur coal and physically cleaned coal potentially available for compliance with three emission standards: 1.2, 0.8, and 0.4 lb $SO_2/10^6$ Btu (0.52, 0.34, and 0.17 kg $SO_2$/GJ). Estimates also were made of the amount of U.S. coal which could be made available if flue gas desulfurization (FGD) or combinations of FGD and PCC were used as the $SO_2$ emission control technique. The effects of coal sulfur variability and required emission averaging time on the amount of available compliance coals also were evaluated. An overview of the technology costs and environmental aspects of both physical and chemical coal cleaning is included, and the applicability of fluidized bed combustion and synthetic fuels for compliance with $SO_2$ emission standards are discussed briefly.

The study results indicate that the use of coal cleaning as an emission control technique will decrease if the emission limits are lowered. Under the current NSPS of 1.2 lb $SO_2/10^6$ Btu (0.52 kg $SO_2$/GJ), an estimated total of 62.4 billion short tons of recoverable reserves could be burned without cleaning or could be cleaned to compliance levels as compared with an estimated portion of this amount of 36.4 billion tons of low-sulfur coal which could be burned without cleaning. Under a limit of 0.8 lb $SO_2/10^6$ Btu (0.34 kg $SO_2$/GJ), these quantities drop to 10.4 and 5.2 billion short tons, respectively. No coal is available even with cleaning which could comply with a limit of 0.4 lb $SO_2/10^6$ Btu (0.17 kg $SO_2$/GJ). A short-term averaging requirement would reduce substantially the quantities available to meet either the 1.2 or 0.8 lb $SO_2/10^6$ Btu (0.52 or 0.34 kg $SO_2$/GJ) limit. The combination of coal cleaning plus FGD would be useful in meeting a 0.4 lb $SO_2/10^6$ Btu (0.17 kg $SO_2$/GJ) emission standard. At this emission level coal cleaning could nearly double the available reserve as compared with the use of FGD alone. For other emission limits, the applicability of coal cleaning combined with FGD will depend upon the cost effectiveness of this approach.



This report was submitted in partial fulfillment of Contract No. 68-02-2163, Task 851, by Battelle's Columbus Laboratories under the sponsorship of the U.S. Environmental Protection Agency. Portions of the work were performed by Hoffman-Muntner Corporation, Silver Spring, Maryland, under subcontract to Battelle's Columbus Laboratories.

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## LIST OF CONVERSION FACTORS

Btu (at 60 F) x 1.055 x $10^3$ = Joule (j)

feet x 0.3048 = meter (m)

degrees Fahrenheit (f) -32 x 0.555 = degrees Celsius (C)

pound mass (lb) x 0.4536 = Kilogram (kg)

Btu/pound (lb) x 2.326 x $10^{-3}$ = Mega Joule/kg (MJ/kg)

lb/$10^6$ Btu x 0.4299 = kg/GJ (kg/$10^9$J)

short ton (2000 lb) x 0.906 = metric ton (1000 kg) = k kg

dollars/short ton x 1.1023 = dollars/metric ton

dollars/$10^6$ Btu x 0.9479 = dollars/GJ ($/$10^9$ J)

pound force per square inch (psi) x 6.89 x $10^3$ =
Pascal (Pa) = Newton/m2) ($N/m^2$)

gallon (U.S.) x 3.78 = liter

barrel (42 gallon) x 158.97 = liter

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Significant contributions to this report were made by Mr. Lawrence Hoffman and Mr. Jerome Hoffman, both of Hoffman-Muntner Corporation, Silver Spring, Maryland, and as a result, these contributors are listed as co-authors of this report.

The advice and counsel of the EPA project Officer Mr. James D. Kilgore, and the liasion provided by Mr. Charles Sedman of the Office of Air Quality Planning and Standards were invaluable in the performance of this work.

# INTRODUCTION

This report has been prepared to provide information to EPA's Office of Air Quality Planning and Standards (OAQPS) for a feasibility study pertaining to possible revision of New Source Performance Standards (NSPS) for power boilers. The report stresses physical coal cleaning as a control technique for $SO_2$ emissions, and includes an analysis of the availability of low-sulfur coal and of coal cleanable to compliance levels under various alternative NSPS. The results of the availability analysis and brief discussions of the applicability of other control techniques to meet optional NSPS are summarized in the study results section. Details of the projections of coal demand for power boilers, and a description of the methodology for estimating coal availability are presented in the subsequent sections. The final section contains an overview of the technology, costs, and environmental aspects of both physical and chemical coal cleaning processes.

During the course of the study questions have arisen regarding the validity of the data base on coal reserves. Project staff consulted directly with Bureau of Mines personnel associated with the development of the reserve data and determined that revisions now in progress are not expected to result in major changes in the data. In addition, coal cleanability data are limited in scope and extrapolations based on the limited data cannot be expected to be as accurate as they will be when broader cleanability data become available. The results of the availability analysis are, of course, subject to modifications as the Bureau of Mines reserve data are refined and as additional cleanability studies are performed. However, the analysis is based on the best data currently available and the results are believed to be a reasonably good representation of the actual potential availability of low-sulfur coal and cleanable coal.

## CONCLUSIONS

The potential role of physical coal cleaning (PCC) for control of $SO_2$ emissions from utility boilers was evaluated for three alternative New Source Performance Standards (NSPS). The approach employed was based on a determination of the quantities of raw coal and of coal cleaned to various levels which could be burned in compliance with $SO_2$ emission standards of 1.2, 0.8, and 0.4 lb $SO_2/10^6$ Btu (0.52, 0.34, and 0.17 kg $SO_2$/GJ). The impact of the variability of sulfur in coal on the quantities of raw and cleaned coal which could be burned in compliance with various emission limits also was evaluated. The combined use of coal cleaning and flue gas desulfurization (FGD) was examined, and the applicability of fluidized bed combustion and of coal conversion processes to meet alternative NSPS was reviewed briefly.

The evaluations were made using U.S. Bureau of Mines coal reserves and coal washability data bases.

The results of the study may be summarized by the following conclusions.

(1) It is estimated that a total of 62.4 billion short tons of recoverable coal reserves could be burned without cleaning or could be physically cleaned to comply with existing NSPS for $SO_2$ emissions. This compares with 36.4 billion short tons of recoverable reserves of low-sulfur coal which could be burned without cleaning.

(2) If emission limits are lowered and short-term averaging is required, PCC alone will be of limited value as an emission control technique as illustrated by the following tabulation.

| Emission Control Technique | $SO_2$ Emission Limit, lb/$10^6$ Btu | | | | | |
|---|---|---|---|---|---|---|
| | 1.2 | | 0.8 | | 0.4 | |
| | Long-Term Average | 30-Day Average | Long-Term Average | 30-Day Average | Long-Term Average | 30-Day Average |
| | Recoverable U.S. Reserves, billions of short tons | | | | | |
| Low-Sulfur Coal | 36.4 | 17.3 | 5.2 | 1.6 | 0.0 | 0.0 |
| Low-Sulfur Coal Plus Cleaned Coal* | 62.4 | 32.3 | 10.4 | 7.1 | 0.0 | 0.0 |

* Cleaned at 1.5 inches top size with Btu recovery greater than 90 percent. Tonnages do not reflect Btu or weight loss during cleaning.

(3) PCC can be combined with FGD to meet reduced emission limits. The combination is particularly effective for a standard of 0.4 lb $SO_2/10^6$ Btu (0.17 kg $SO_2$/GJ) because large quantities of high-sulfur coals cannot be cleaned to this level with FGD alone. The following tabulation summarizes the tonnages of coal which would be potentially available using low-sulfur coal with FGD or cleaned coal with FGD.

| Emission Control Technique | $SO_2$ Emission Limit, lb/$10^6$ Btu | | | | | |
|---|---|---|---|---|---|---|
| | 1.2 | | 0.8 | | 0.4 | |
| | Long-Term Average | 30-Day Average | Long-Term Average | 30-Day Average | Long-Term Average | 30-Day Average |
| | Recoverable U.S. Reserves, billions of short tons | | | | | |
| Low-Sulfur Coal and FGD | 254.6 | 229.4 | 215.6 | 184.5 | 111.7 | 85.9 |
| Low-Sulfur Coal Plus Cleaned Coal* and FGD | 257.2 | 253.8 | 254.6 | 229.4 | 171.5 | 141.1 |

* Cleaned at 1.5 inches top size with Btu recovery greater than 90 percent. Tonnages do not reflect Btu or weight loss during cleaning.

(4) Although a standard specifying a percentage reduction in sulfur emissions was not addressed in this study, PCC may be useful in combination with other controls in meeting this type of standard. PCC would allow the scrubber or other control system to operate at a lower efficiency since credit would be given to precombustion sulfur removal.

(5) PCC has been used for many years to reduce ash and to enhance the heating value. As such, PCC is an available technology. Improvements designed to increase sulfur removal are being developed and incorporated in the technology. PCC costs vary with the type of coal and the treatment employed. An annualized cost of $\$0.18/10^6$ Btu of cleaned coal is typical.

(6) A number of chemical coal cleaning processes are in various stages of development. These are designed to achieve greater sulfur removal than PCC. However, none of these processes is commercially available at this time. The projected costs range from \$0.60 to $\$1.00/10^6$ Btu of cleaned coal.

## VARIABILITY OF SULFUR IN COAL

The fact that the composition and properties of coal can vary widely, even within a given coal seam, is an important consideration with respect to emission regulations. Because the sulfur content varies, the average value for sulfur in coal can be used to determine compliance with a given standard only if long-term averaging of the resultant $SO_2$ emission is permitted. If, however, the emission limit includes a "never to be exceeded" statement, a coal with average sulfur and heat content values which are equivalent to the stated emission limit will be out of compliance approximately half of the time. The net effect of an emission regulation which calls for anything other than long-term averaging is to require the use of coal with a lower average sulfur content so that when upward deviations from the average occur the unit will still be in compliance. The problem is to determine how much lower the average sulfur content must be.

In this analysis it was assumed that the variation in coal sulfur content follows normal statistical relationships, and the standard deviation of the sulfur values was used to determine the average sulfur content required to meet a given emission limit. It should be noted that insufficient data on coal sulfur variability exist to prove that the assumption of normal statistical behavior is valid for all coals. In fact, the discrete nature of pyritic sulfur in coal seems to preclude the expectation of normal distribution. Nevertheless, the assumption that normal statistics are followed provides a useful approach until more data on sulfur variability are obtained.

For a normal statistical distribution, the frequency of occurrence of various sulfur values would follow a bell-shaped curve of the type shown in Figure 1a and 1b. The highest point on the curve, i.e., the sulfur value which occurs most frequently, represents the average or mean value, designated by $\mu$. If the variability is small, the distribution curve would be tall and narrow, as shown in Figure 1b. A short and broad curve, as shown in Figure 1a, would be obtained if the variability is large. It is apparent that the shape of this sulfur distribution curve has great significance with respect

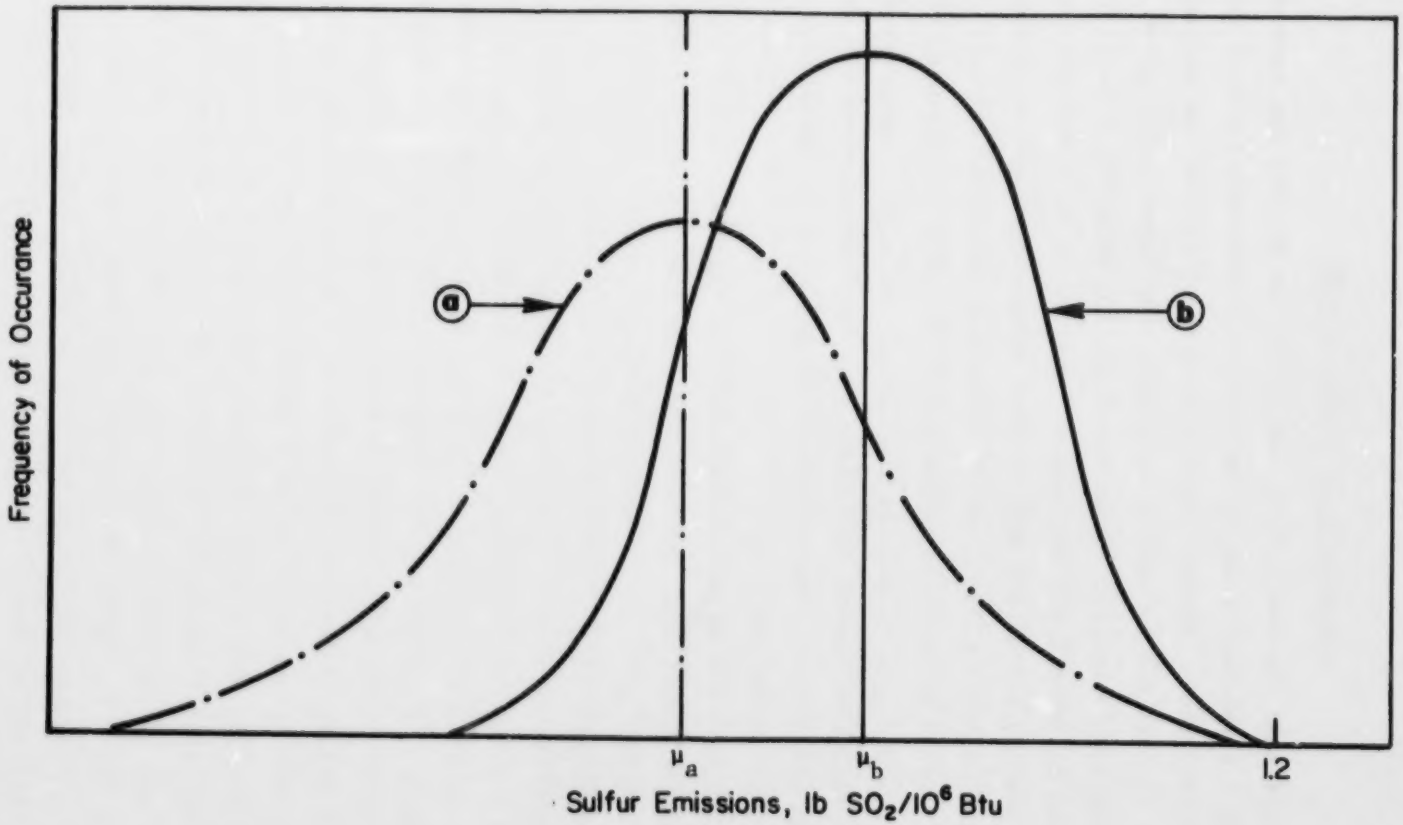



FIGURE 1. EXAMPLES OF NORMAL DISTRIBUTION CURVES

to compliance with a stated $SO_2$ emission limit. A much lower average sulfur content is required for compliance, if the curve is similar to the one shown in Figure 1a, than if it is like the one shown in Figure 1b. One factor which influences the shape of the distribution curve is the size of the sample taken for analysis, i.e., the smaller the sample size, the larger the variation in the observed sulfur values, and, the more the curve will look like Figure 1a rather than Figure 1b. The averaging time used for determining compliance with a given standard similarly influences the shape of the distribution curve. Since the quantity of coal burned during a given averaging time constitutes the sample size, a short averaging time corresponds to a small sample size, and large variations in sulfur content will be observed when compared to a longer averaging time with a correspondingly larger sample size.

The impact of these considerations is shown in the following tabulation, in which the averaging emission level required by different averaging times is listed for various emission limits.

| Emission Standard, lb $SO_2/10^6$ Btu | Average Emission Level Required, lb $SO_2/10^6$ Btu | | |
|---|---|---|---|
| | Long-Term Averaging | 30-Day Averaging* | 24-Hour Averaging* |
| 1.2 | 1.2 | 0.92 | 0.58 |
| 0.8 | 0.8 | 0.62 | 0.30 |
| 0.4 | 0.4 | 0.31 | 0.19 |

* Following recent EPA practice, the relative standard deviation (RSD), defined as $\sigma/\mu$ where $\sigma$ is the standard deviation and $\mu$ is the mean value, was taken as the measure of sulfur variability. A 10 percent RSD was used as representative of a 30-day averaging period and a 99.87 percent confidence level was adopted. For a normal distribution, this level occurs at $\mu$ plus $3\sigma$. This means that a coal with an average $SO_2$ emission of $\mu$ will exceed $\mu + 3\sigma$ only 0.13 percent of the time. A 36 percent RSD and a $3\sigma$ confidence level was used as representative of a 24-hour averaging period.

It is apparent that short-term averaging requirements will greatly reduce the quantities of raw coal and of cleaned coal which could be burned in compliance with any given emission limit, because the average sulfur content required for a 24-hour averaging period is less than one-half of the value required for long-term averaging. The impact of averaging time with respect to a percentage reduction regulation, although not addressed in this study, is expected to be important also.

## RESULTS OF STUDY

### General Discussion

The potential role of coal cleaning and other control technologies as $SO_2$ emission control techniques for utility boilers was evaluated in terms of the quantities of coal reserves which could be used in compliance with various alternative NSPS. Such reserve quantities are referred to subsequently as available coal. In this context, "available" means suitable for compliance with a given emission standard, rather than ready for use. For each alternative NSPS, the quantities of available coal were determined for different combinations of control technology application. These tonnages are compiled in Tables 13-23 in a later section. In order to emphasize the impact of various NSPS on the potential demand for coal cleaning and other control techniques, the coal quantities in tons were converted to years of coal availability by dividing by an assumed annual utility consumption of coal. In each case the utility consumption of coal projected for 1985 was arbitrarily selected for this conversion factor. The resulting quantities, years of coal availability, are not intended to reflect the actual lifetimes of coal reserves, since other coal uses, logistics of transportation, contractual arrangements, etc., have not been considered. Rather, the years of coal availability are merely numbers which reflect, on a regional basis, both the reserves and a significant fraction of the total coal demand. It is this ratio of potential supply and potential demand which more clearly reflects the impact of revised NSPS on the potential for coal cleaning to serve as an $SO_2$ control measure for utility boilers.

The use of electricity is expected to increase during the period 1976-1985, possibly at a lower annual rate than observed in past decades. Demand and energy requirements will be closely allied to the state of the economy and real growth of the Gross National Product. Conservation, higher prices for electricity, and a slight decrease in the rate of population growth will tend to reduce the growth rate while the curtailment of gas and oil use will tend to increase it. The Federal Power Commission has projected that the total national electric energy requirement in 1985 will be within the approximate range of 3 to 3.5 million gigawatt-hours (1 gigawatt is one million kilowatts). This compares with about 2.2 million gigawatt hours in 1977.

The Energy Policy and Conservation Act of 1975 was enacted "to increase domestic energy supplies and availability; to restrain energy demand; to prepare for energy emergencies; and for other purposes." Many of the provisions of this act will have significant impact on the availability of fuels to the electric industry.

The bill provides for the extension of the Federal Energy Administration's (FEA) coal conversion authority enforceable through January 1, 1985. With this authority the FEA can order a power plant which is burning oil or gas to switch to coal, if the plant has coal burning capabilities. The conversion must also be approved by the Environmental Protection Agency. The FEA has estimated that if all units considered as potential candidates for conversion are in fact converted to coal, utility annual coal demand would be increased by 42.6 million kkg (47 million tons) by 1984.

The FPC estimates that electric power generation by coal-fired boilers will increase from 45% in 1975 to 49% in 1985. This translates into an annual utility demand for coal of 715 million kkg (788 million tons) in 1985. The conversion-to-coal demand would therefore increase this amount by approximately 6%.

A further potential influence on projected utility coal demand is the National Energy Plan proposed by President Carter. Which portions of this plan will be enacted is not clear at this time. However, various government agency analysts have concluded that it is not likely to have a large impact on utility coal use.

## Availability of Low-Sulfur Coal, Physically Cleaned Coal, and Flue Gas Desulfurization to Meet Optional NSPS

Given the projected utility demand for coal, an analysis was conducted of the availability of low-sulfur coal and physically cleaned coal to meet this demand. The availability was determined for various alternative NSPS and, for comparison, for the case of no emission standards. The availability of coal which could meet the various NSPS with coal cleaning together with flue gas desulfurization (FGD) also was determined.

The bounded solution to this analysis was obtained by using:

1) The projected annual demand for coal, by all the coal-fired electric utilities (existing and new) scheduled for 1985 operation
2) The annual coal demand by the potential utility candidates for conversion from oil and gas to coal
3) The demonstrated recoverable coal reserve base
4) The potential cleanability of the reserve base
5) Assumptions regarding the effectiveness of FGD applied to the combustion products from cleaned coal
6) Assumptions regarding the variability of sulfur in coal.

The analytical methodology and the detailed results are described in a subsequent section. Summaries of the results of the analysis are displayed in the form of bar charts in Figure 2, in which sulfur variability is not considered, and Figure 3, in which sulfur variability effects are included. The bar chart is an effective means of conveying the effects of emission regulations and techniques for compliance on the coal availability throughout the United States. The definitions of the regions designated are given in Table 1.

The nature of the information presented in Figure 2 may be illustrated by reference to the four bars for the entire United States. If there were no emission standards, the demonstrated recoverable coal reserve base could supply the utility demand for 330 years if consumed at the projected 1985 rate. For a NSPS of 1.2 pounds $SO_2$ per $10^6$ Btu, raw coal availability drops to 46 years. Physical cleaning to the level noted increases the availability to 79 years. If FGD and PCC were applied, the availability becomes 326 years. This is almost the equivalent of the raw coal recoverable reserve. This simply means that there is a small amount of coal which could not meet a 1.2 pounds $SO_2$ per $10^6$ Btu on a long term averaging basis even with PCC and FGD applied. If the NSPS were reduced to 0.8 pounds $SO_2$ per $10^6$ Btu, raw coal and PCC coal availability both drop still further. Essentially no raw coal or coal which could be sufficiently cleaned is available if the NSPS were reduced to 0.4 pounds $SO_2$ per $10^6$ Btu, and the availability drops to 218 years if both PCC and FGD control techniques were applied. A regional breakdown also is presented in Figure 2.

FIGURE 2

COAL AVAILABILITY BAR CHART

STATUS OF THE AVAILABILITY OF COAL TO MEET THE NSPS OPTIONS
FOR ALL COAL-FIRED UTILITIES OPERATING IN 1985 (EXISTING PLUS NEW)
RAW AND PREPARED COAL WITH AND WITHOUT FLUE GAS DESULFURIZATION (FGD)

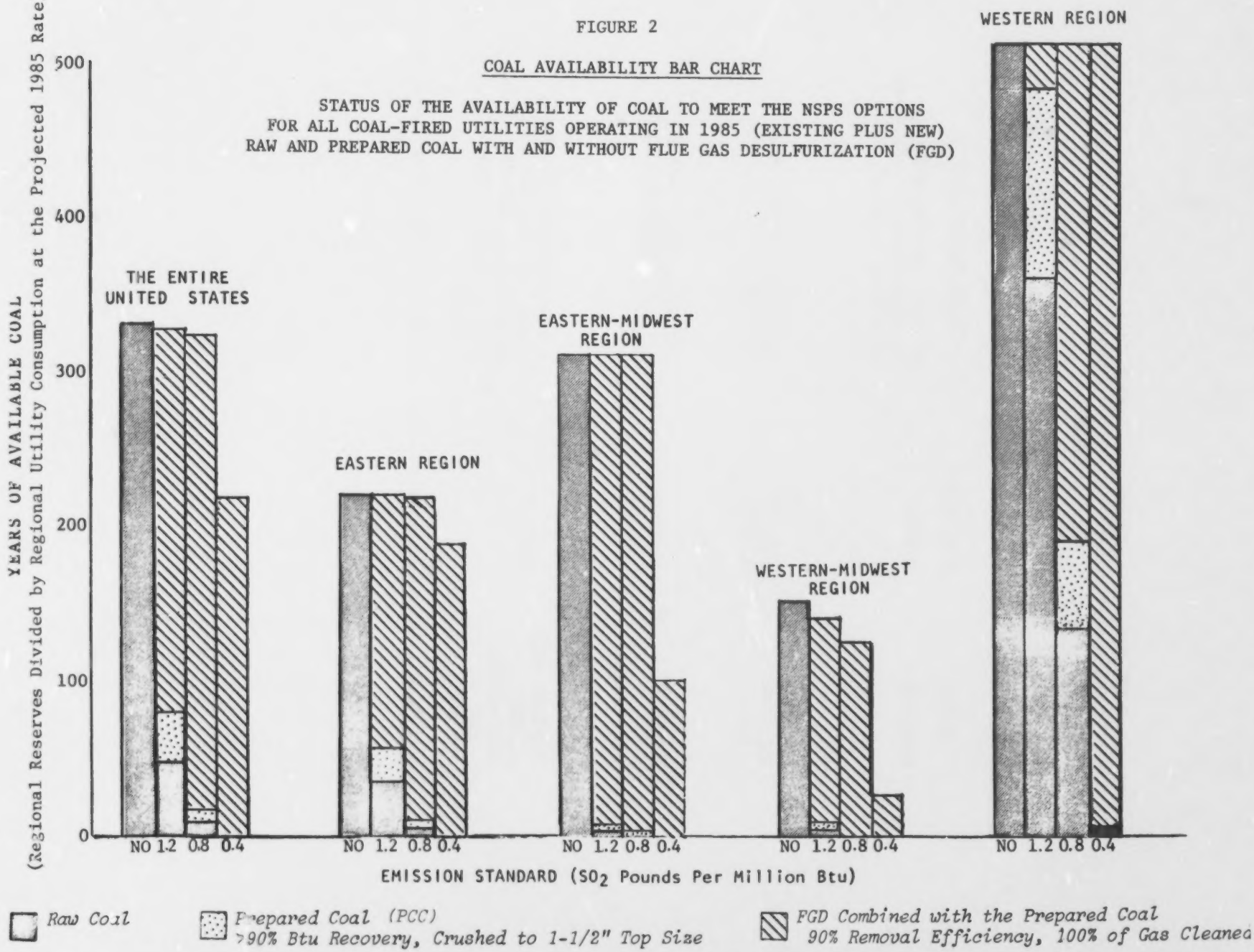


TABLE 1

DEFINITION OF COAL PRODUCING REGIONS

| REGION | DESIGNATION | STATES ENCOMPASSED |
|---|---|---|
| APPALACHIA | EASTERN | ALABAMA, EAST KENTUCKY, MARYLAND, OHIO, PENNSYLVANIA, TENNESSEE, VIRGINIA, WEST VIRGINIA. |
| INTERIOR BASIN | EASTERN MIDWEST | ILLINOIS, INDIANA, WEST KENTUCKY. |
| BUREAU OF MINES DISTRICT 15 | WESTERN MIDWEST | ARKANSAS, IOWA, KANSAS, MISSOURI, OKLAHOMA, TEXAS |
| NORTHERN GREAT PLAINS THE ROCKIES, AND THE PACIFIC | WESTERN | ALASKA, ARIZONA, COLORADO, IDAHO, MONTANA, NEW MEXICO, NORTH DAKOTA, OREGON, SOUTH DAKOTA, UTAH, WASHINGTON, WYOMING |

For each region the available coal in the region is compared with the projected 1985 utility demand for coal in the same region.

All of the information presented in Figure 2 is based on average sulfur values. Consideration of the effect of sulfur variability was incorporated in the analysis as summarized in Figure 3. The net effect of requiring short-time averaging in determining compliance with a stated emission limit is to reduce the availability of raw coal and of cleaned coal, as can be seen by comparing Figure 3 with Figure 2.

The summary results of Figures 2 and 3 indicate the following conclusions.

1) PCC alone will be of limited value in meeting reduced NSPS for utilities. PCC should have a role in combination with FGD.
2) FGD or other control techniques with comparable sulfur-removal effectiveness will be required, if more stringent $SO_2$ emission standards are imposed.
3) If the practicality of coal distribution from one region to another region were ignored, and if it were assumed that the coal reserves were available for use anywhere in the United States, compliance with more stringent regulations would still be impossible without FGD or comparable control techniques.
4) Since the potential for conversion from oil and gas to coal would increase the demand for coal by only 6 percent, this by itself would only cause a small ripple effect in the coal availability results.

Somewhat more detailed summaries of the results of the availability analysis are presented in Figures 4-13. These sets of curves cover the four major coal-producing regions plus a composite graph for the entire United States. In each case the first figure shows coal availabilities based on average sulfur content, while the figure immediately following shows coal availabilities obtained with consideration of the variability of sulfur in coal. For example, Figure 6 shows results for the Eastern Region on the basis of average sulfur content. If there were no NSPS, the "Maximum Years

FIGURE 3

COAL AVAILABILITY BAR CHART

STATUS OF THE AVAILABILITY OF COAL TO MEET THE NSPS OPTIONS
FOR ALL COAL-FIRED UTILITIES OPERATING IN 1985 (EXISTING PLUS NEW)
RAW AND PREPARED COAL WITH AND WITHOUT FLUE GAS DESULFURIZATION (FGD)

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

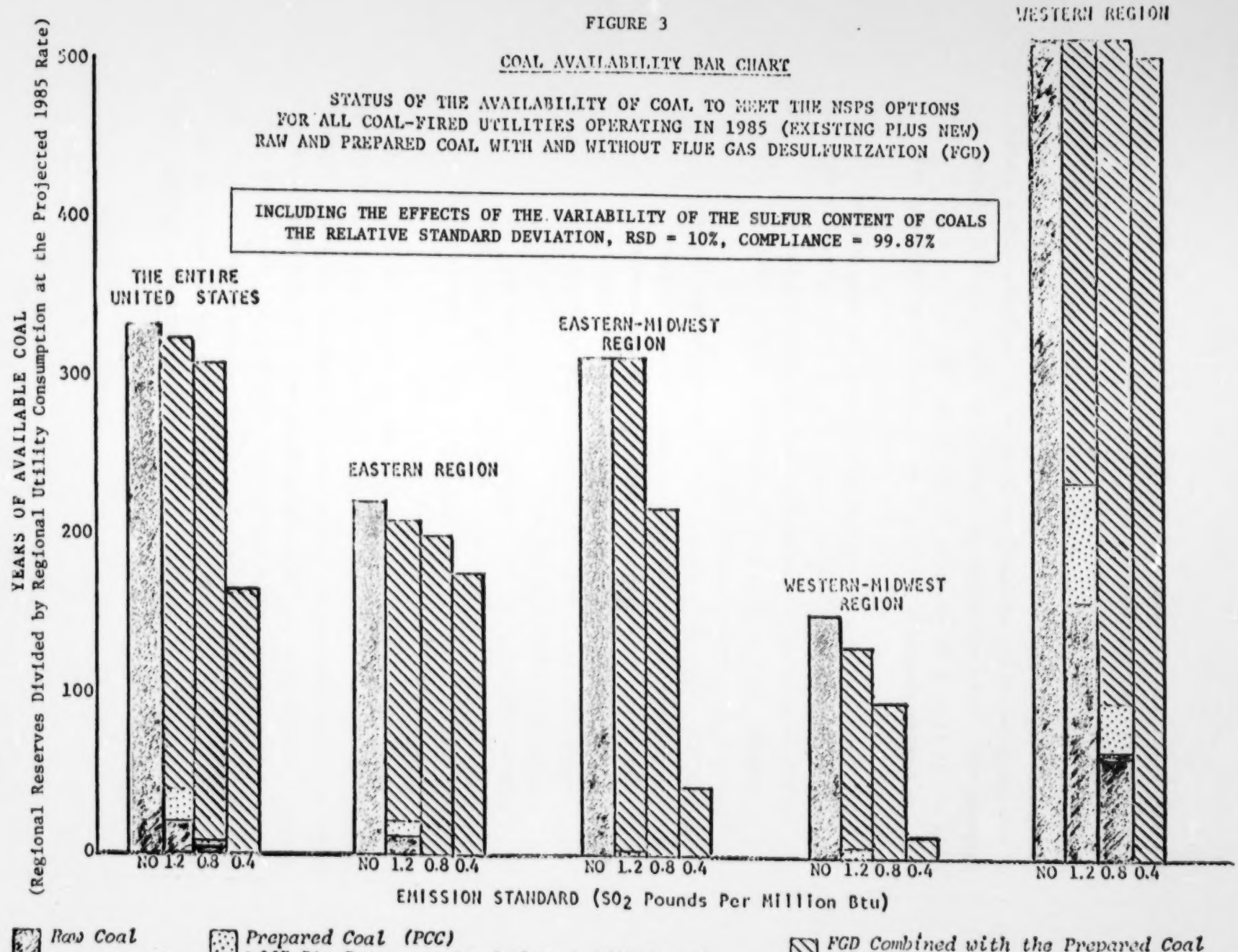
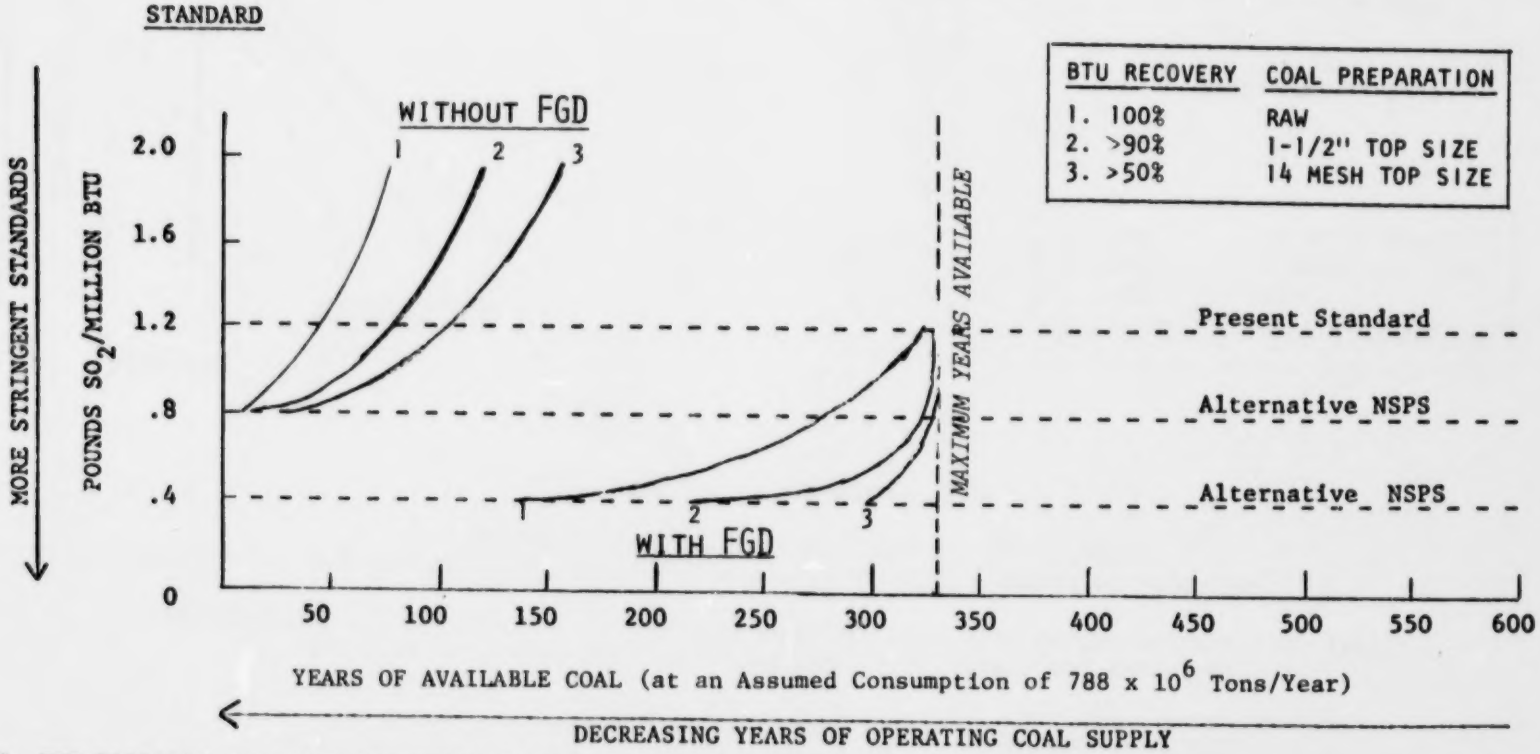


FIGURE 4

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION, FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

THE ENTIRE UNITED STATES




NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily affects curve 3, showing a higher coal availability than is actually the case).

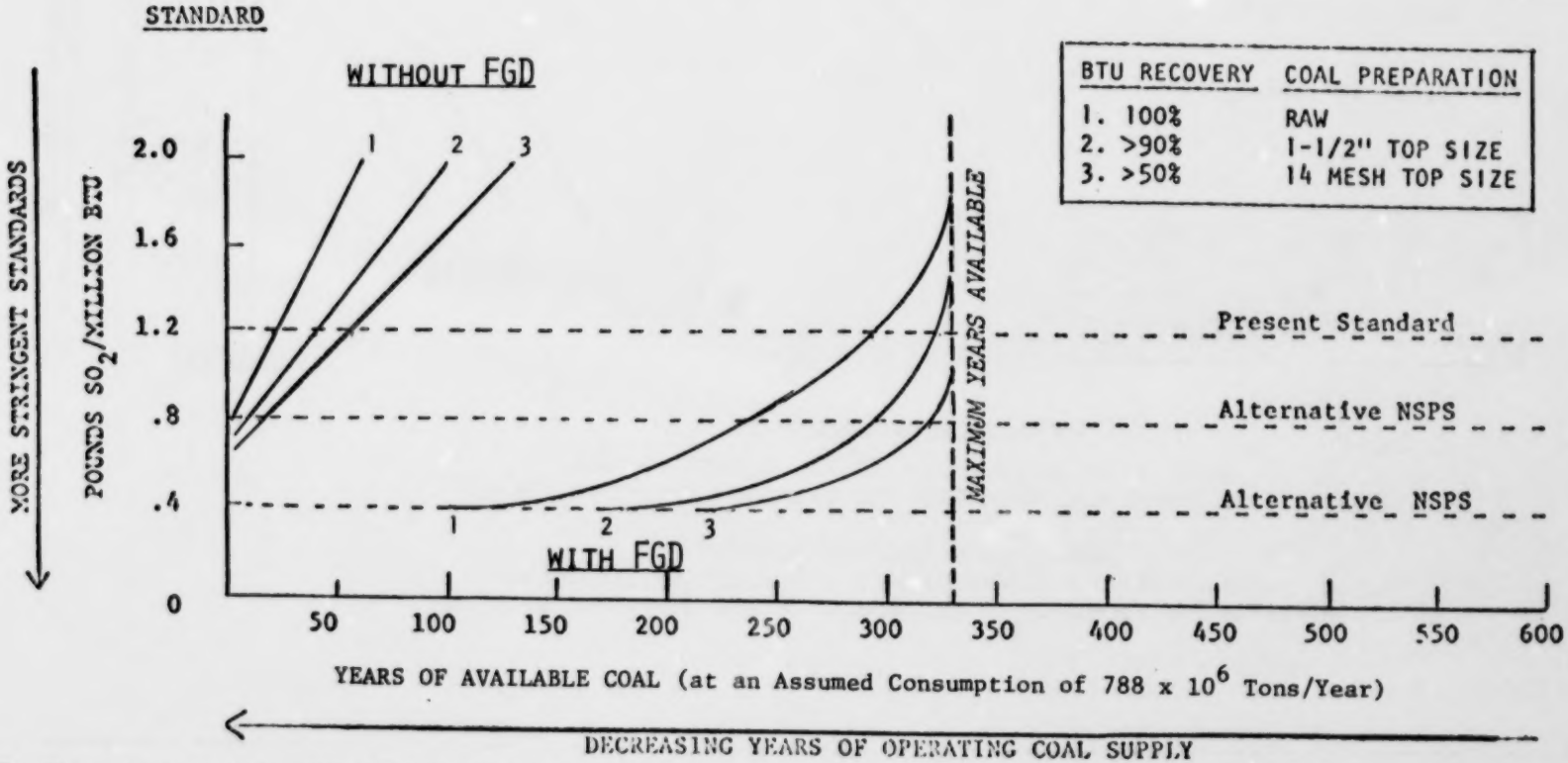
FIGURE 5

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD).

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

THE ENTIRE UNITED STATES



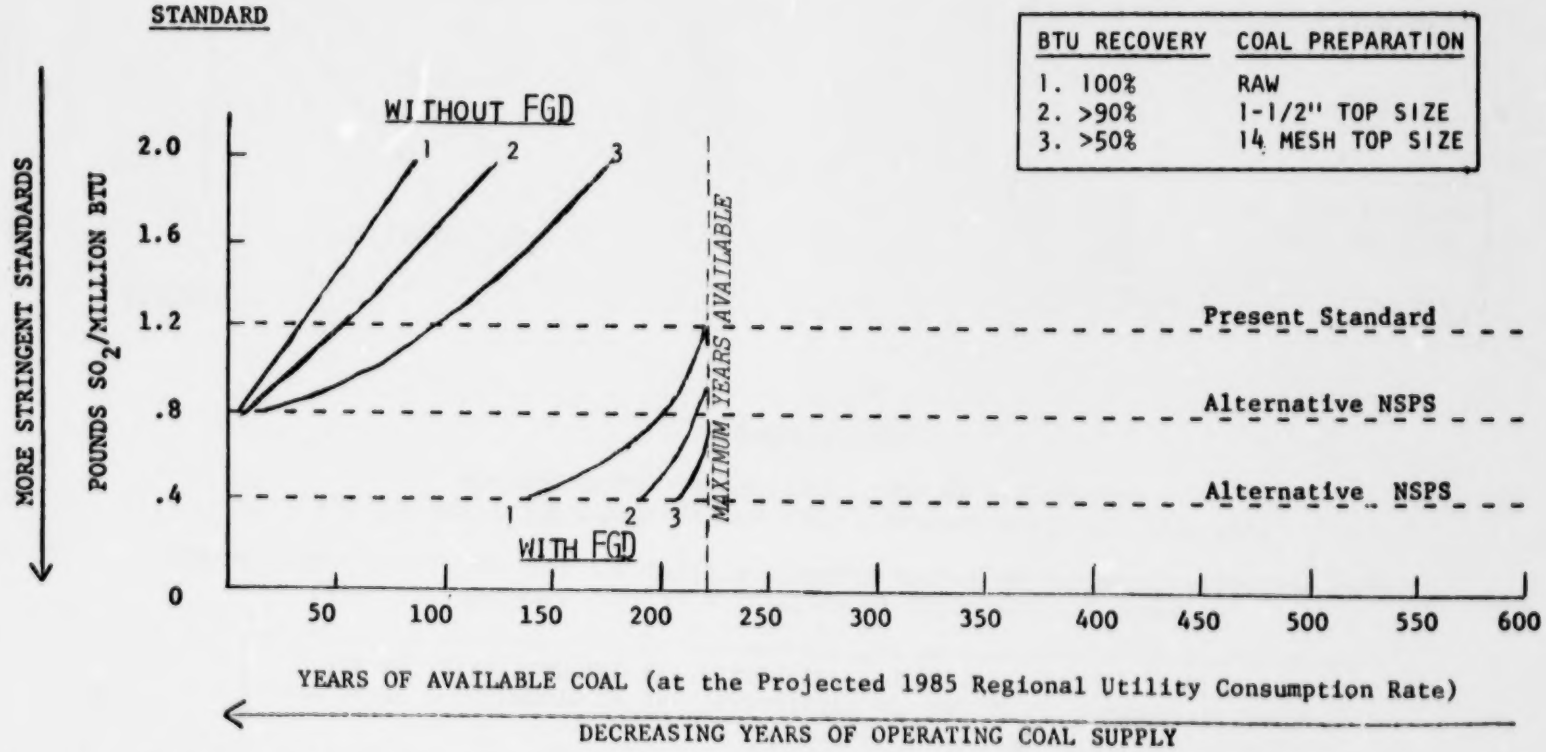

NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily affects curve 3, showing a higher coal availability than is actually the case).

FIGURE 6

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION, FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN REGION




NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATION (This primarily affects curve 3, showing a higher coal availability than is actually the case).

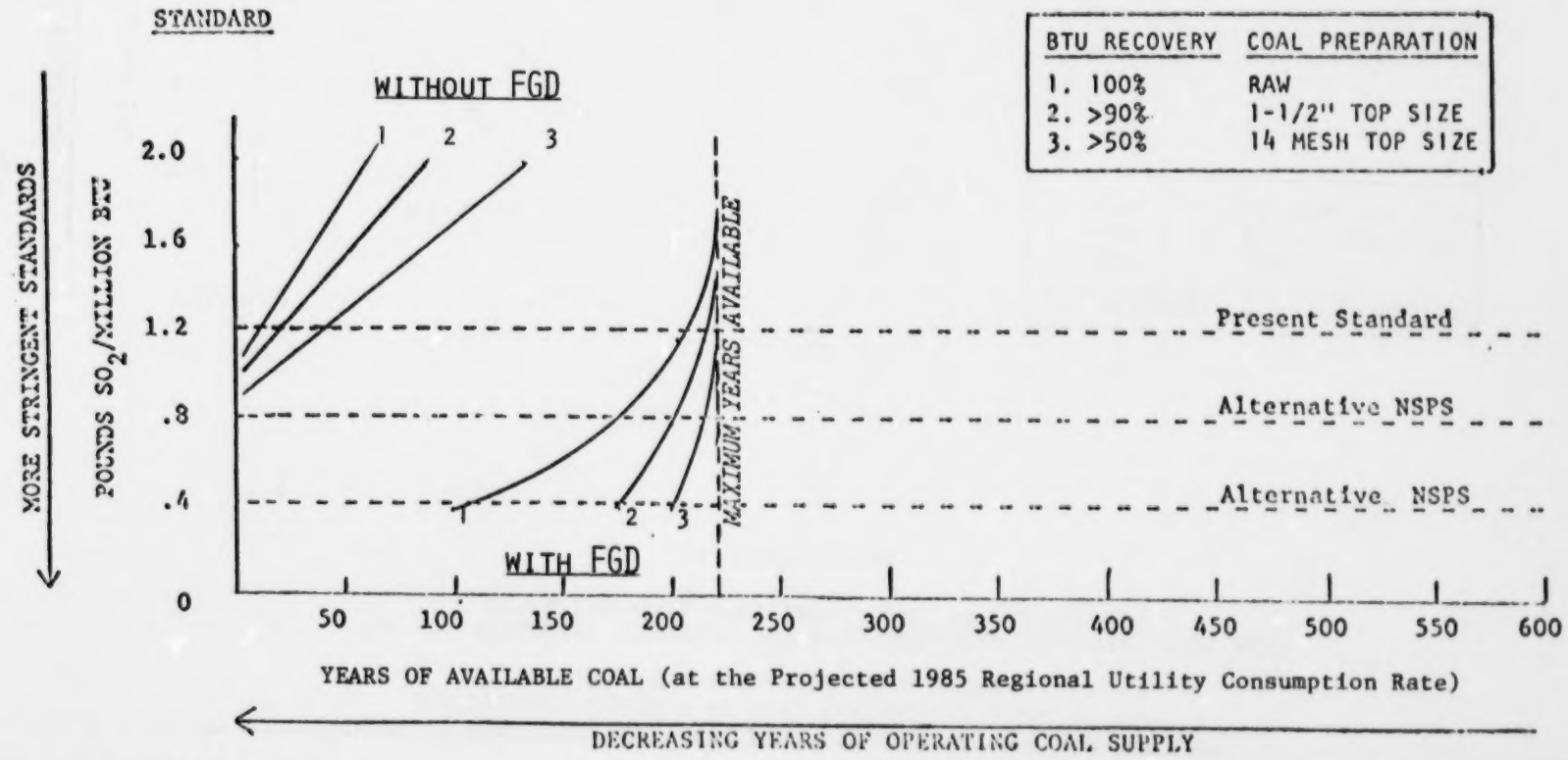
FIGURE 7

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD).

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN REGION



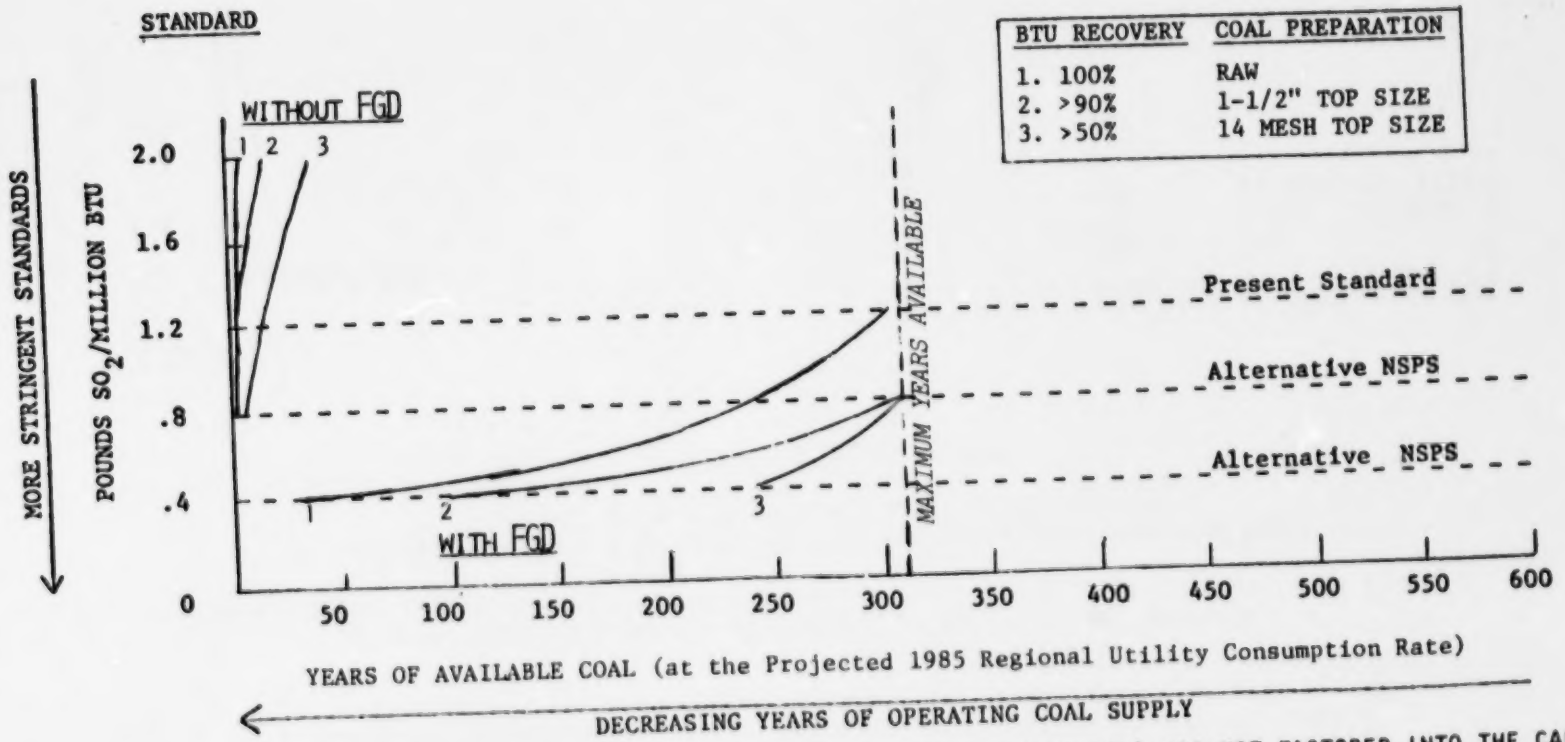

NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS (this primarily affects curve 3, showing a higher coal availability than is actually the case).

FIGURE 8

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH
FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN - MIDWEST REGION




NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily affects curve 3, showing a higher coal availability than is actually the case).

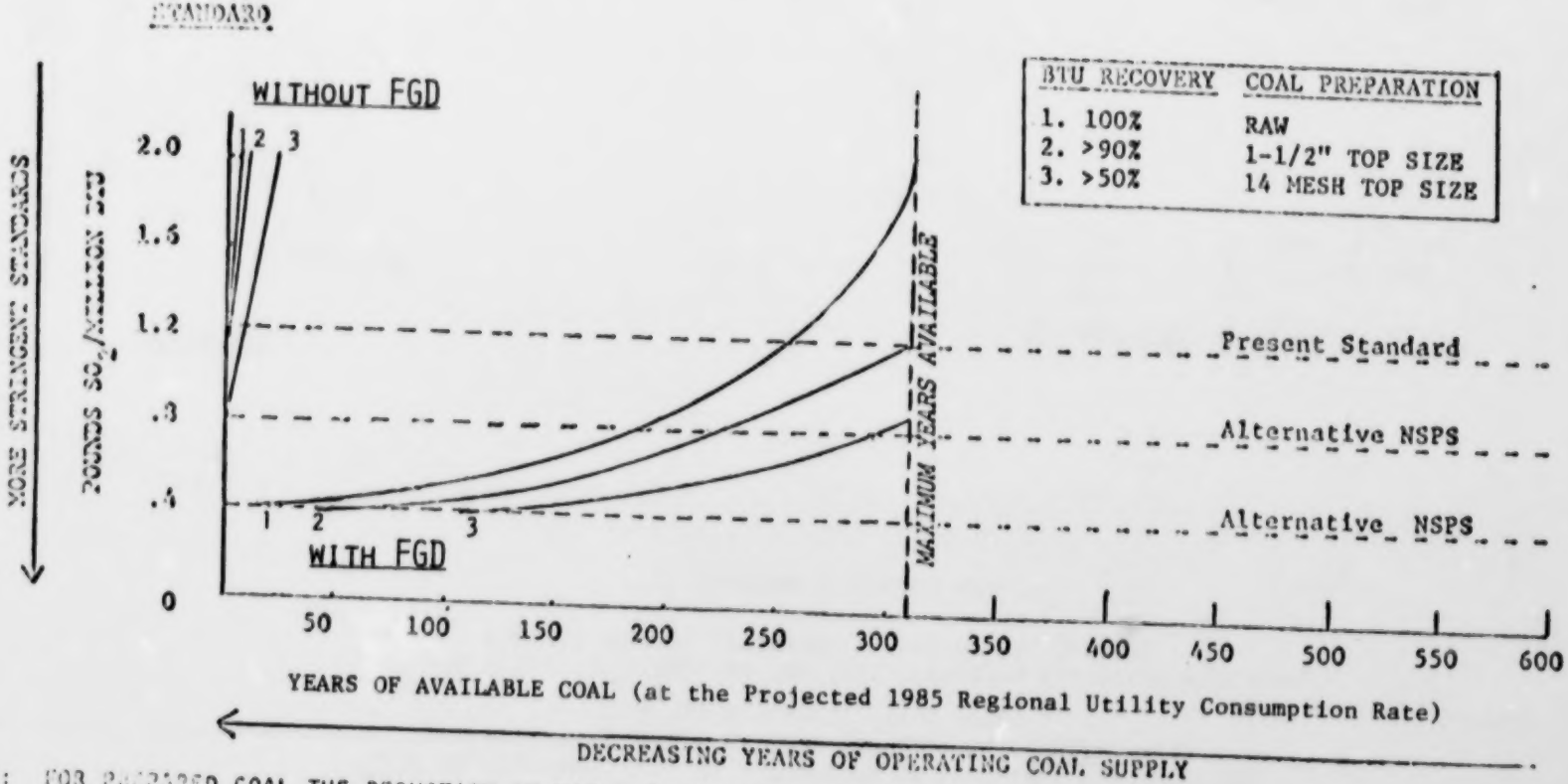
FIGURE 9

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVJATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN - MIDWEST REGION



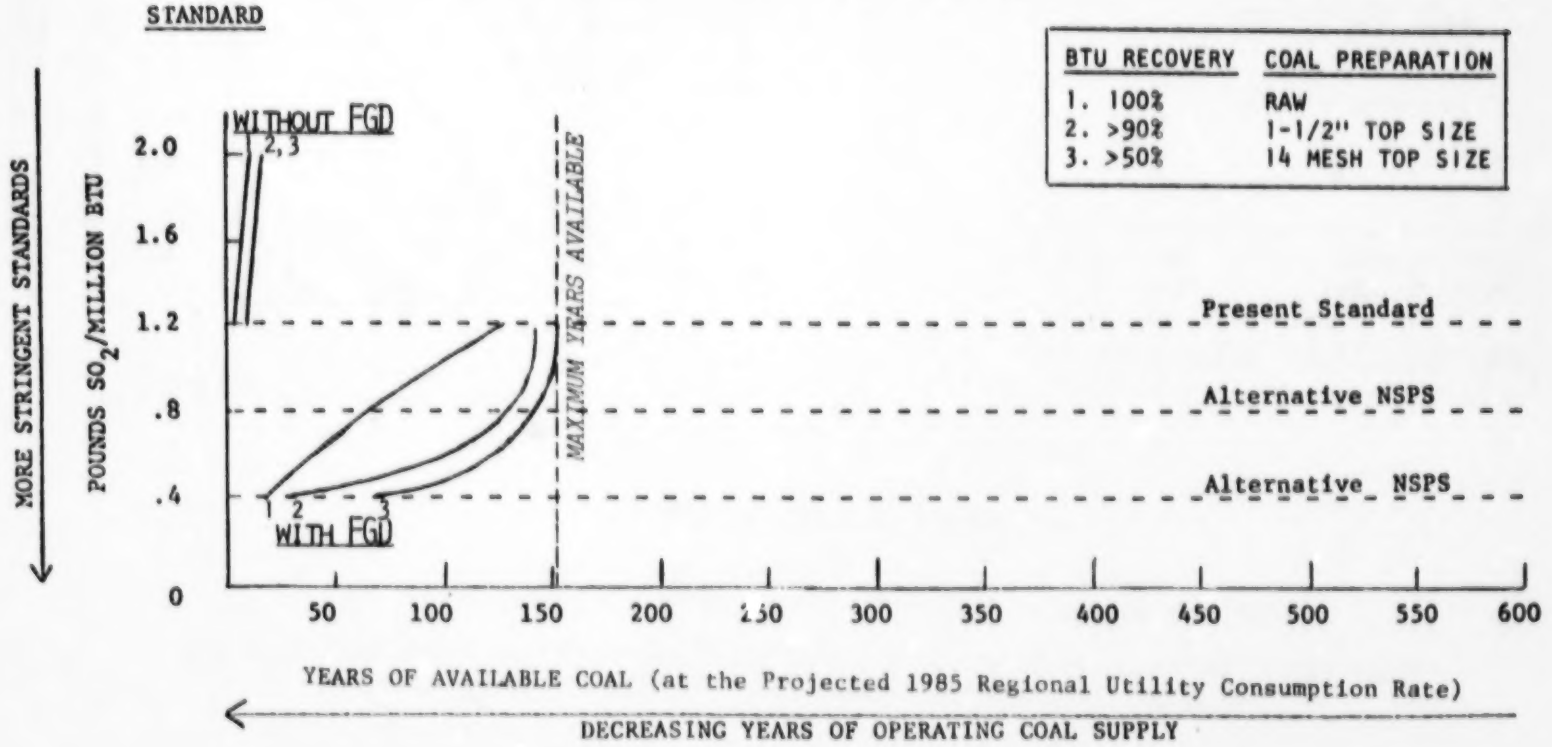

NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily affects curve 3, showing a higher coal availability than is actually the case).

FIGURE 10

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH
FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN - MIDWEST REGION




NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS.
(This primarily affects curve 3, showing a higher coal avilability than is actually the case).

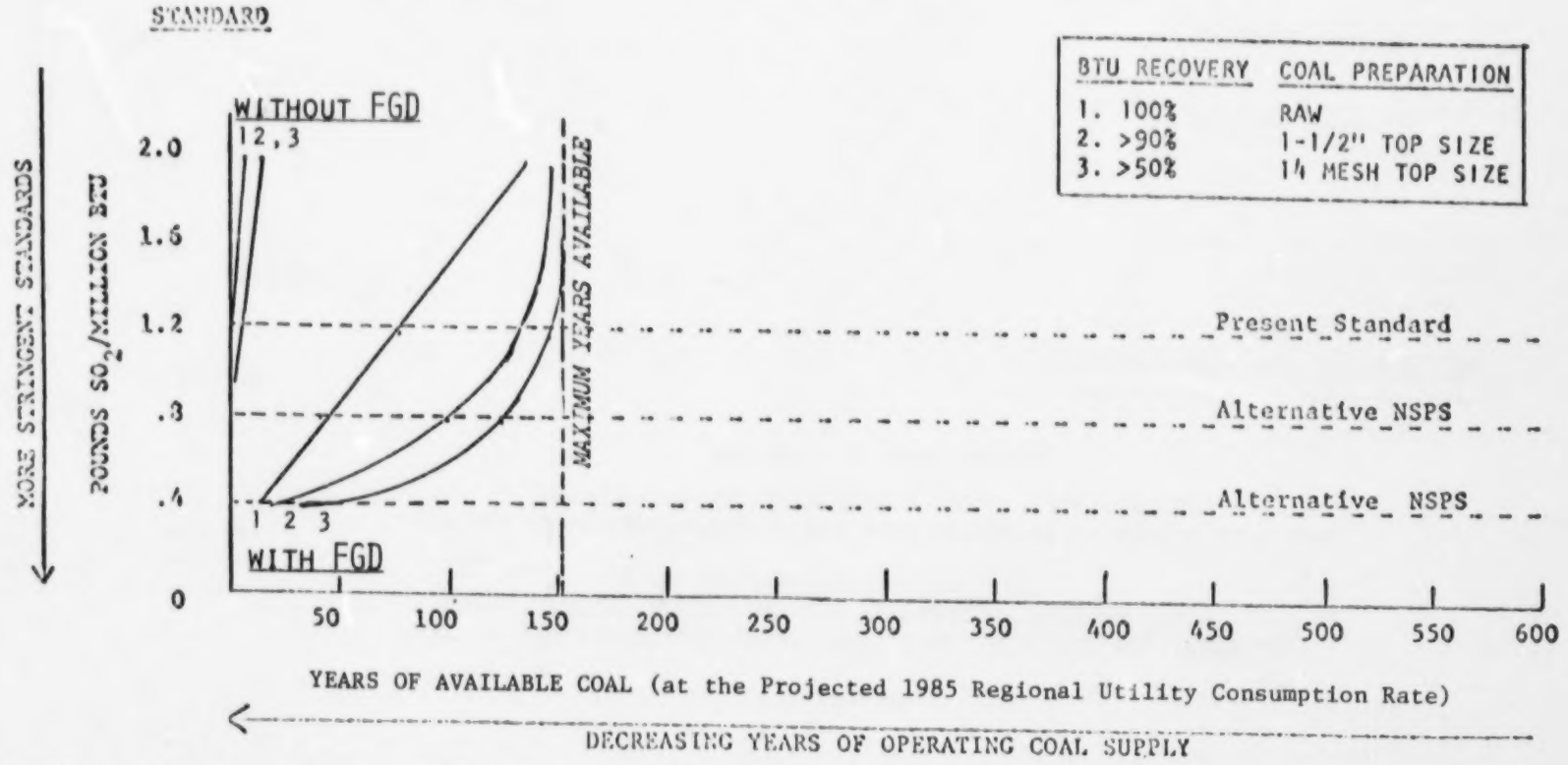
FIGURE 11

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD).

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN - MIDWEST REGION



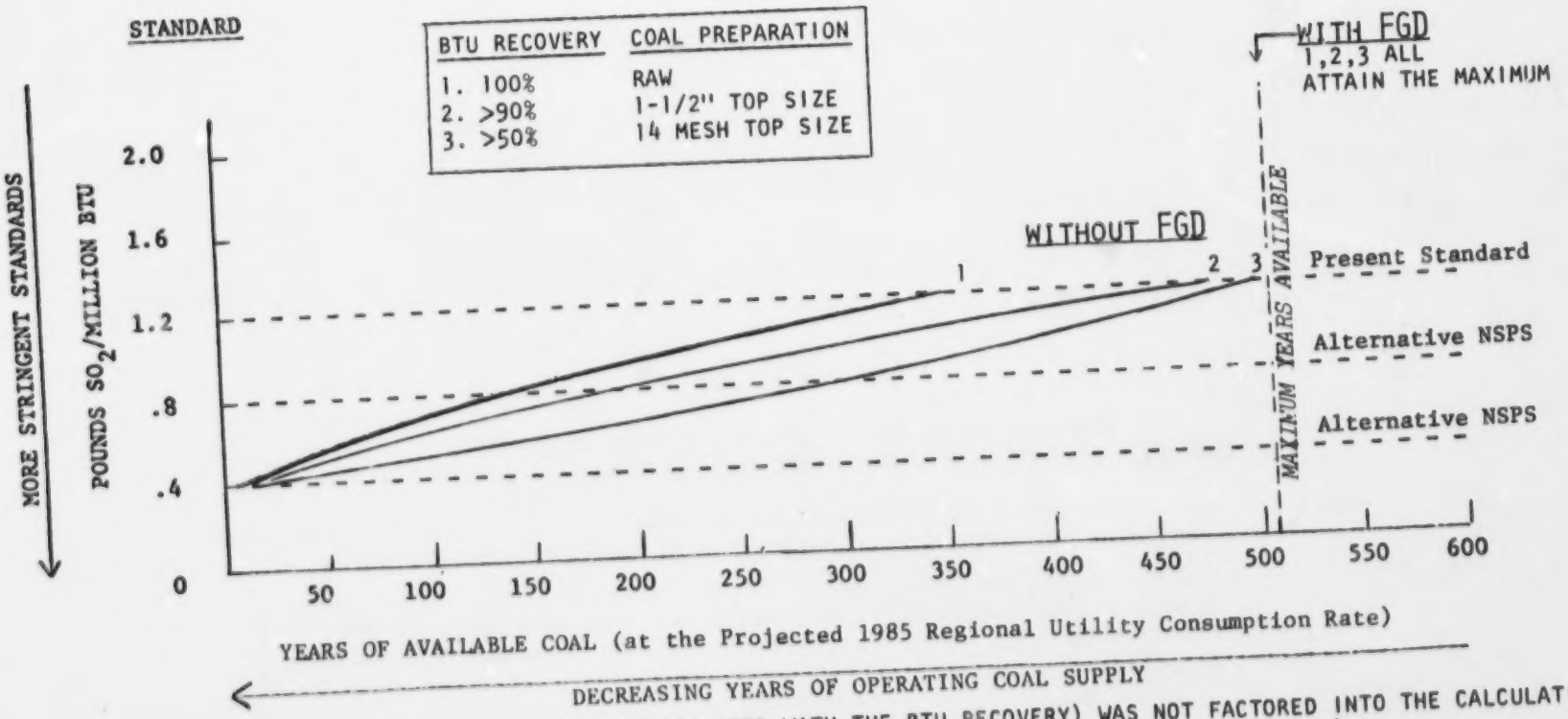

NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS.
(This primarily affects curve 3, showing a higher coal availability than is actually the case.)

FIGURE 12

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION, FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN REGION




NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS. (This primarily affects curve 3, showing a higher coal availability than is actually the case).

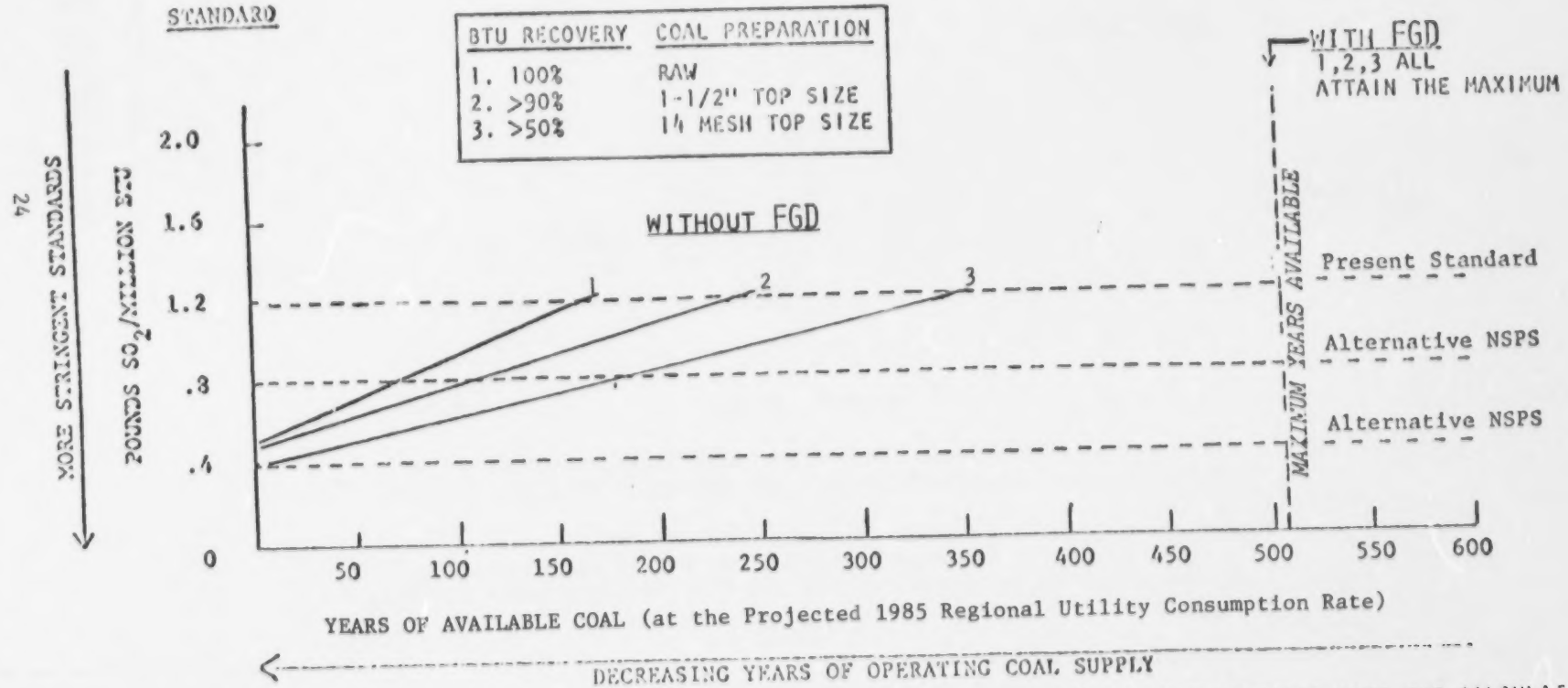
FIGURE 13

INCLUDING THE EFFECTS OF THE VARIABILITY OF THE SULFUR CONTENT OF COALS
THE RELATIVE STANDARD DEVIATION, RSD = 10%, COMPLIANCE = 99.87%

YEARS OF AVAILABLE COAL AS A FUNCTION OF ALLOWABLE $SO_2$ EMISSION,
FOR DIFFERENT LEVELS OF COAL PREPARATION COMBINED WITH FLUE GAS DESULFURIZATION (FGD)

FOR ALL UTILITIES SCHEDULED FOR 1985 OPERATION (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN REGION




NOTE: FOR PREPARED COAL THE REDUCTION IN YIELD (ASSOCIATED WITH THE BTU RECOVERY) WAS NOT FACTORED INTO THE CALCULATIONS.
(This primarily affects curve 3, showing a higher coal availability than is actually the case).

Available" of raw coal is approximately 220 years. However, at the present 1.2 NSPS, only 34 years of raw coal, and 56 years of cleaned coal (Curve 2 without FGD) are available. The curves in Figure 7 show that sulfur variability considerations reduce these values to 10 years and 20 years, respectively.

It should be noted that these results are bounded by the assumptions outlined in the section on methodology. These assumptions are such that maximum availabilities (given the reserve base and washability data) are obtained for each selected control technique and NSPS. Lesser quantities may, in fact, be available as a result of logistical, economic, or contractual factors which have not been considered in this analysis.

## FGD Considerations

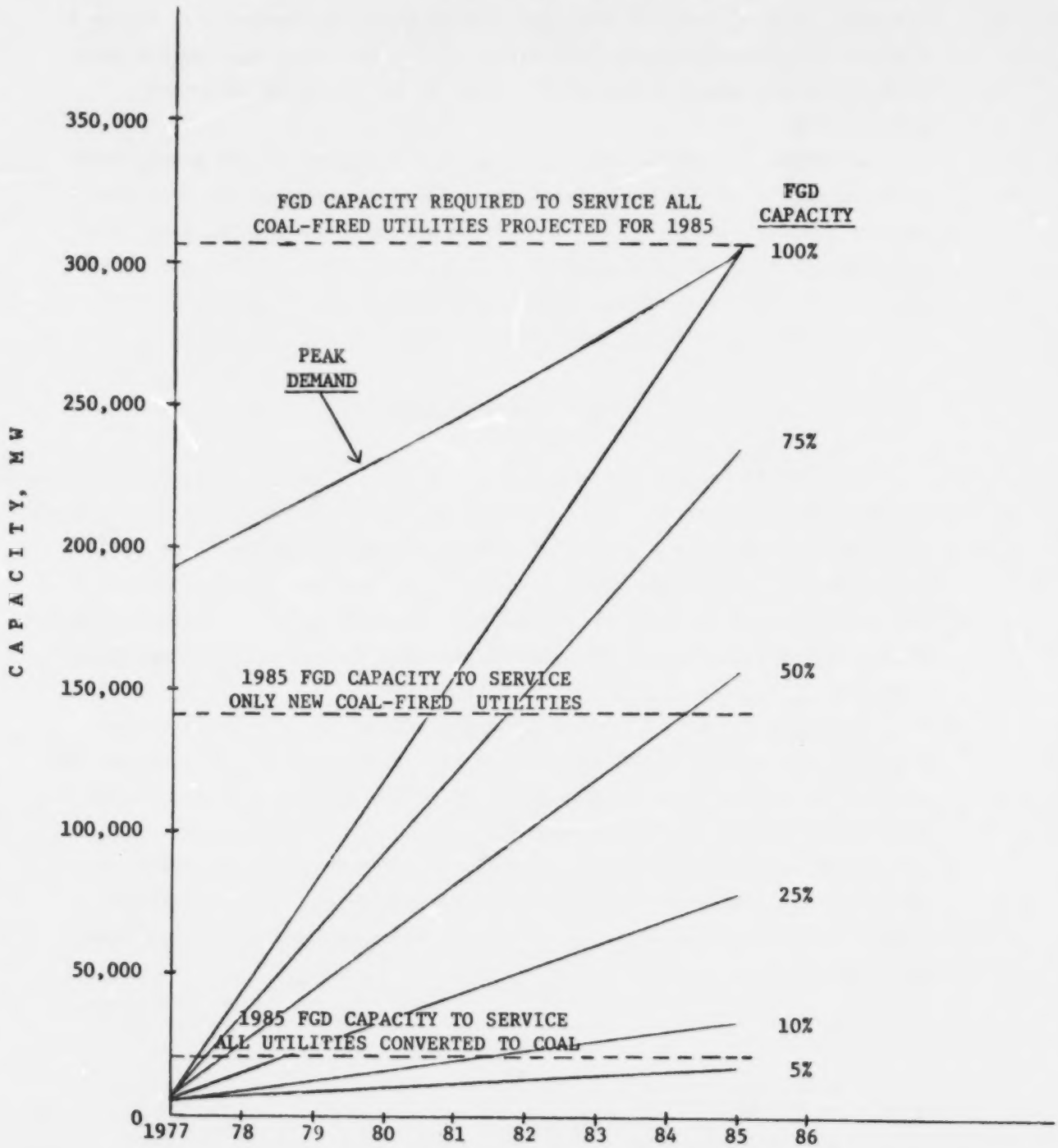
The Federal Power Commission has obtained preliminary data (currently being updated) showing that the total FGD capacity in operation in the United States, as of the beginning of the calendar year 1977, was 3,716 MW. From the following section of this report, Table 3, we find that the peak demand in the United States for 1977 is 396,359 MW. The portion of this demand supplied by coal-fired utilities is 45%. Therefore, the FGD cpaacity is approximately 2 percent of the peak demand for coal-fired units.

The projected peak demand for the coal-fired electric utilties for the 1977-1986 period is shown in Figure 14. Also shown is the required FGD capacity to service a given percentage of the total capacity of the coal-fired utilities in the United States.

A tabulation of projected utilization of FGD by new coal-fired units which was attributed to PEDCO was received from OAQPS. This tabulation shows a cumulative FGD capacity of 140,000 MW by the end of 1985 as shown in Figure 14.

FIGURE 14

PROJECTED CAPACITY DEMAND-
PEAK POWER DEMAND AND REQUIRED FGD CAPACITY



## Applicability of Combined Physical Coal Cleaning (PCC) and Flue Gas Desulfurization (FGD) to Meet Optional NSPS

The sulfur and ash contents of coal are reduced by physical coal cleaning (PCC), with the attendant benefits of reduced transportation costs, reduced ash-handling costs at the point of use, improved boiler operation and efficiency, and reduced $SO_x$ and particulate emissions when the cleaned coal is burned. However, the sulfur-reduction potential is limited since the organic sulfur cannot be removed by this process. Therefore, not all coals can be cleaned to compliance levels, and, as noted in the preceding section, if the NSPS is reduced, the applicability of PCC as the sole control measure vanishes. Another possible approach to $SO_x$ control could be the combined use of PCC and flue gas desulfurization (FGD). This combination of control techniques was considered in the availability analysis of the preceding section. If PCC, a relatively low-cost process, can be used to reduce the sulfur content to near the NSPS compliance level, then FGD, a relatively high-cost process, could be used to treat just a portion of the flue gas stream in order to achieve NSPS compliance. The size of the FGD unit required, and hence its cost, would be reduced. A further benefit would accrue from using FGD on only a portion of the flue gas if the recombined treated and untreated flue gas streams retain sufficient bouyance that reheat would not be required to achieve plume rise.

The economics of combined PCC and FGD have been analyzed by Hoffman-Muntner Corporation in a study for EPA through the Bureau of Mines*, and by PEDCo-Environmental Incorporated in a study for EPA/RTP**. These studies showed that a lower cost can be expected by using the combined technologies if the sulfur content of the cleaned coal is near compliance levels. As the difference between sulfur content and compliance level increases, FGD must be used on a greater percentage of the flue gas, reducing the potential benefits which accrue from scrubbing only a fraction of the flue gas stream. However, because there are many variables involved, it is not possible to reach a general conclusion regarding the cost effectiveness of using PCC combined with FGD as a sulfur control measure, thus, the required analysis must be done in a site-specific framework. For example, Eastern underground coal mined by continuous mining techniques generally must be cleaned to remove high levels

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* See Reference 1 on page 97.

** Miranda, C. F., et al., "An Optimization Strategy for Control of $SO_x$ From Coal-Fired Power Plants".

of mineral matter as a prerequisite for satisfactory boiler operation. In such a case, the incremental cleaning cost to achieve effective sulfur removal may be more than offset by reduced scrubbing costs, even if much of the flue gas stream must be scrubbed.

A standard specifying a percentage reduction in sulfur emissions was not considered among the alternative NSPS during the course of this study. However, a standard requiring 90 percent sulfur removal has been proposed by EPA since the completion of this analysis. Although the proposed rule would allow credit for precombustion sulfur removal, no PCC process can achieve 90 percent sulfur removal. Thus, it would seem that, if such a standard were adopted, PCC might not have a useful role. But, on the other hand, PCC could be used as a means of reducing the efficiency requirements of the scrubber. As an example, if 50 percent of the sulfur were removed by coal cleaning, then the scrubber would have to operate at only 80 percent removal to achieve the 90 percent removal required by the proposed rule. In view of the current status of scrubber technology, the difference between 80 and 90 percent removal would be a significant consideration in the design of a new system. Furthermore, if a scrubber system, installed for the purpose of meeting 90 percent removal, failed to operate consistently at that level, a switch to cleaned coal might provide the solution to the problem. In light of such considerations, PCC could have a role in meeting a percentage removal standard.

## Applicability of Fluidized-Bed Combustion to Meet Optional NSPS

Fluidized-bed combustion (FBC) of coal is a technology under development which has several attractive features. The fluidized-bed system provides high heat transfer rates, allowing smaller sized units for a given capacity. The maximum combustion temperature is reduced, resulting in lower $NO_x$ production. Finally, if the fluidized bed is composed of a reactive solid, $SO_2$ can be removed in the combustion zone. Reactive bed materials of calcined dolomite (MgO·CaO) or calcined limestone (CaO) have been studied most extensively.

In practice, the amount of $SO_2$ removed by a CaO bed is not controlled by thermodynamic equilibrium. The partial pressure of $SO_2$ in equilibrium with CaO, $CaSO_4$, and $O_2$ is $1.25 \times 10^{-7}$ atm at 1656 F, or about 0.125 ppm. This very low value is not achieved in practice because equilibrium is not reached. Relatively high $SO_2$ removal has been obtained in experimental units by using greater than stoichiometric quantities of CaO. This need to have Ca/S ratios of 2 or greater leads to large quantities of spent limestone. This material must be disposed of in a once-through system design. Research on methods of regenerating the spent bed material are in progress. The excess CaO required for efficient $SO_2$ removal complicates the regeneration processes by increasing the quantity of material to be processed. For these reasons considerable research is being devoted to keeping the Ca/S ratio requirement at a minimum.

Reduction of NSPS for $SO_2$ would not, out of hand, preclude the further development of FBC as a control technique, since, as indicated above, the practical $SO_2$ removal efficiency is not controlled by thermodynamic equilibrium. However, a reduced NSPS would require the use of increased Ca/S ratios to obtain the higher $SO_2$ removal efficiencies needed for compliance. Since it is desirable to minimize the Ca/S ratio, this would be expected to delay the development of FBC to some extent.

In summary, theoretically FBC can be employed as a control technique to meet reduced emission standards. Whether or not this can be achieved practically and economically depends on the course of the research and

development activities. Reduced emission standards would be expected to make the development task more difficult.

## Applicability of Coal Conversion Processes to Meet Optional NSPS

One of the alternative approaches to the control of $SO_x$ emissions associated with the use of coal in stationary sources is the conversion of coal to a clean fuel by gasification or liquefaction. Research efforts to produce clean fuels from coal are proceeding along three major lines:

- High-Btu gas or synthetic natural gas (SNG)
- Low-Btu gas
- Synthetic liquids [the product of the solvent refined coal (SRC) process is actually a solid at ambient temperature].

None of these processes is sufficiently developed to serve as a near-term $SO_x$ control technique. SNG is not expected to be used as a boiler fuel. The price will be too high, and the eventual need to replace natural gas in the residential sector will preclude burning SNG under boilers.

Low-Btu gas has promise as a boiler fuel, particularly for plants in which the gasification process is integrated with a combined-cycle power plant. Such integrated designs offer promise of minimum heat rejection, and hence, improved overall conversion efficiency. The sulfur problem remains but is dealt with differently. In most gasification processes sulfur is volatilized under reducing conditions to form $H_2S$, scrubbed from the fuel gas, stripped from the absorption liquor as a concentrated $H_2S$ stream, and converted to sulfur using Claus plant technology. If strict emission regulations are applied to such processes, a Claus plant tail gas treatment process will be required. Direct oxidation systems, such as the Stretford process, etc., may be used in lieu of the absorption/Claus approach.

Liquefaction processes involve hydrogeneration of coal to produce various liquids. Sulfur is released in the processing as $H_2S$ which is scrubbed from the byproduct gas. The liquids produced are low in sulfur content and can be burned without subsequent $SO_x$ control.

In summary, coal conversion processes to produce clean fuels are not sufficiently developed to serve as near-term $SO_x$ control techniques. Reduced emission standards for stationary combustion sources will not impact on these processes in the long term since the sulfur problem is encountered in the conversion step. Regulations applicable to such processing will have an impact on the final cost of the clean fuel.

## ELECTRIC POWER SUPPLY AND DEMAND 1977-1986

### General Discussion

The information in this section concerns the bulk electric power supply and demand in the contiguous United States as projected for the period 1977-1986. It was obtained from the Federal Power Commission Bureau of Power Staff Report. Data as to projected electrical demands, energy and generating capability have been summarized from the reports filed with the Commission on April 1, 1977, by the Regional Electric Reliability Councils, in response to FPC Order 383-4. Council acronyms and geographic boundaries are given in Figure 15.

Formation of the councils was given impetus by the Commission recommendation that the utility industry establish "strong regional organizations" to coordinate planning, construction and operation of the national bulk electric power supply. Through the standing and special committees of the councils, planning and operating personnel of the electric utilities (Federal, state and municipally owned, privately owned and cooperatively owned) endeavor to provide for rational economic development of electricity supply. The Commission, in promulgating its series of orders (383-1, -2, -3, -4) related to reliability and adequacy of bulk power supply, set up a frame of reference for the compilation of certain planning data on a long-range regional basis. The essential ingredients of satisfactory power supply are load forecasts made with reasonable confidence, timely installation of new generating plants, a properly coordinated transmission network and dependable supplies of fuel for electric generation. Since 1970, the councils in responding to the series of "383" orders have been furnishing data enabling the Commission to monitor electric system planning in the large.

The electric utility power system in the U.S. is made up of three component networks. The seven strongly interconnected council areas (ECAR, MAAC, MAIN, MARCA, NPCC, SERC, AND SWPP) comprise essentially a single

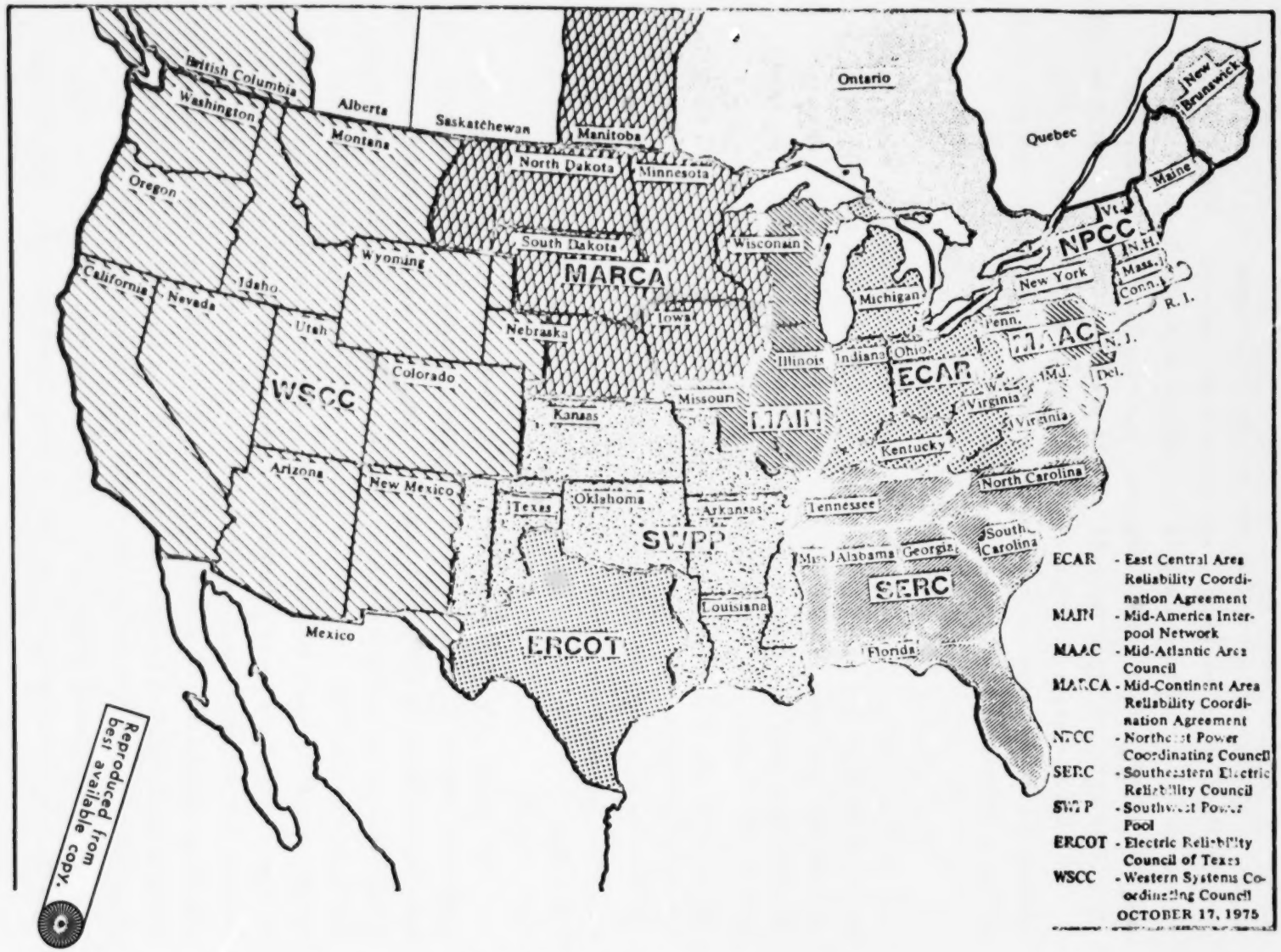


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FIGURE 15. REGIONAL ELECTRIC RELIABILITY COUNCILS

network covering all or part of 39 states. Interconnections among the systems in the seven councils are sufficient for the interchange of significant amounts of power in emergencies and for economic purposes. The 14 western states (all or in part) are within the area of WSCC, which, while it has numerous intraregional interconnections, has only minor interconnection capability with the other regional council areas. ERCOT is the third network.

The ERCOT systems comprise an interconnected group that has no transmission interconnections with any other council region, supplying power only within a large part of the State of Texas.

## Peak Demand Forecasts

"Peak Demand" in its customary electric power system sense means the greatest one-hour use of electric energy during a specified period. Most systems have two periods when use of electricity is high: summer and winter. In many regions of the country, use of electric power is greater in summer than in the winter, hence the "summer peak demand" is greater than the "winter peak demand". The projected council summer and winter peak demands for the period 1977-1986 are listed in Table 2. The contiguous United States average annual summer and winter growth rates for the period are 5.7% and 5.8%, respectively (Table 3). Note that the data reported were developed and compiled in late 1976 and early 1977, and reflect economic expectations then current.

The growth rate of demand reflects the combined workings of several factors as viewed by the electric utilities: attempts at load management and conservation; higher electricity prices and new pricing schedules; a lower growth rate of the national economy. Substitution of electricity for fossil fuels, where feasible, will tend to offset the foregoing. An additional factor, which may have different weights in different areas, is increased use of electricity caused by environmental pressures. Air pollution abatement devices, for instance, may use electrostatic precipitators, thus directly requiring greater use of electricity. Or, mechanical and chemical methods of removing potential pollutants, by increasing the obstruction to flow of process gases and the gases resulting from combustion, require greater fan capacity which results in more use of electricity. In power plants, the use of scrubbers for flue gas desulfurization, precipitators that remove extremely high percentages

TABLE 2

PEAK DEMAND [1]
AS PROJECTED APRIL 1, 1977
BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
CONTIGUOUS UNITED STATES
MEGAWATTS

SUMMER PEAK DEMAND

| YEAR | ECAR [5] | ERCOT | MAAC | MAIN | MARCA [2] | NPCC [2] N.E. [3] | NPCC [2] N.Y. [4] | SERC FLORIDA | SERC SOUTHERN | SERC TVA | SERC VACAR | SWPP | WSCC [2] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1977 | 59,838 | 27,582 | 32,650 | 33,663 | 17,664 | 13,905 | 21,590 | 15,681 | 19,946 | 20,150 | 26,245 | 37,132 | 70,313 |
| 1978 | 63,461 | 29,305 | 34,200 | 35,716 | 18,945 | 14,648 | 22,430 | 16,692 | 22,095 | 21,650 | 28,044 | 39,895 | 74,867 |
| 1979 | 67,156 | 31,077 | 35,780 | 37,932 | 20,278 | 15,455 | 23,340 | 17,796 | 23,977 | 23,350 | 29,995 | 42,586 | 78,971 |
| 1980 | 71,150 | 32,920 | 37,400 | 40,170 | 21,783 | 16,315 | 24,230 | 18,902 | 25,816 | 25,050 | 32,073 | 45,832 | 83,666 |
| 1981 | 75,111 | 34,830 | 39,030 | 42,417 | 23,349 | 17,209 | 25,040 | 20,041 | 27,814 | 26,250 | 34,096 | 48,806 | 88,051 |
| 1982 | 79,323 | 37,016 | 40,730 | 44,832 | 24,882 | 18,152 | 25,850 | 21,214 | 29,769 | 27,400 | 36,099 | 52,278 | 92,345 |
| 1983 | 83,655 | 38,996 | 42,450 | 47,402 | 26,376 | 19,125 | 26,850 | 22,347 | 31,848 | 28,650 | 38,044 | 56,053 | 96,839 |
| 1984 | 88,318 | 41,255 | 44,230 | 50,172 | 27,887 | 20,166 | 27,950 | 23,422 | 33,930 | 29,950 | 40,375 | 60,019 | 101,364 |
| 1985 | 93,186 | 43,234 | 46,030 | 53,040 | 29,500 | 21,255 | 28,910 | 24,453 | 36,081 | 31,250 | 42,780 | 64,214 | 106,542 |
| 1986 | 98,293 | 45,438 | 47,810 | 56,039 | 31,066 | 22,384 | 29,930 | 25,490 | 38,561 | 32,650 | 45,297 | 68,660 | 111,350 |

WINTER PEAK DEMAND

| YEAR | ECAR [5] | ERCOT | MAAC | MAIN | MARCA [2] | NPCC [2] N.E. [3] | NPCC [2] N.Y. [4] | SERC FLORIDA | SERC SOUTHERN | SERC TVA | SERC VACAR | SWPP | WSCC [2] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1977 | 58,987 | 19,161 | 27,970 | 27,315 | 15,931 | 15,217 | 19,690 | 15,708 | 16,960 | 23,150 | 25,179 | 26,350 | 68,829 |
| 1978 | 62,481 | 20,551 | 29,490 | 29,192 | 16,960 | 16,051 | 20,450 | 16,762 | 18,270 | 25,100 | 27,106 | 28,133 | 73,142 |
| 1979 | 66,370 | 21,746 | 31,010 | 31,108 | 18,166 | 16,918 | 21,340 | 17,802 | 19,611 | 27,200 | 29,234 | 30,278 | 77,371 |
| 1980 | 70,175 | 23,012 | 32,530 | 33,097 | 19,448 | 17,846 | 22,150 | 18,938 | 21,050 | 28,700 | 31,447 | 33,604 | 81,617 |
| 1981 | 74,386 | 24,446 | 34,200 | 35,300 | 20,754 | 18,820 | 22,990 | 20,043 | 22,558 | 30,100 | 33,703 | 34,671 | 85,840 |
| 1982 | 78,713 | 26,024 | 35,850 | 36,615 | 21,958 | 19,814 | 23,870 | 21,124 | 24,132 | 31,550 | 36,051 | 36,993 | 90,202 |
| 1983 | 83,255 | 27,395 | 37,560 | 38,942 | 23,221 | 20,851 | 24,850 | 22,165 | 25,840 | 33,050 | 38,551 | 39,841 | 94,731 |
| 1984 | 88,128 | 29,046 | 39,310 | 41,377 | 24,723 | 21,964 | 25,920 | 23,194 | 27,690 | 34,650 | 41,140 | 42,686 | 99,221 |
| 1985 | 93,195 | 30,420 | 41,050 | 43,707 | 26,141 | 23,134 | 26,880 | 24,217 | 29,538 | 36,300 | 43,805 | 46,686 | 104,376 |
| 1986 | 98,548 | 31,918 | 42,830 | 46,605 | 27,661 | 24,379 | 27,880 | 25,235 | 31,783 | 38,150 | 46,571 | 48,833 | 109,273 |

1/ The demands listed include interruptible loads and exclude inter-regional purchases and sales.
2/ Includes only United States portion of Council.
3/ Total for the six New England states.
4/ New York Power Pool.
5/ Revised demand data for ECAR was obtained too late to be incorporated in this report. However the greatest change for any year would be less than one tenth of one percent.

SOURCE: April 1, 1977 responses to Appendix A-1 of FPC Docket R-362 (Order 383-4), Item No. 1.

TABLE 3

PROJECTED GROWTH OF PEAK DEMAND[1/]
CONTIGUOUS UNITED STATES
1977-1986

SUMMER PEAK DEMAND PERIODS

| Year | Total U. S. Peak Demand | Annual Increase MW | Annual Increase % |
|---|---|---|---|
| 1977 | 396,359 | -- | - |
| 1978 | 421,948 | 25,589 | 6.5 |
| 1979 | 447,693 | 25,745 | 6.1 |
| 1980 | 475,307 | 27,614 | 6.2 |
| 1981 | 502,064 | 26,757 | 5.6 |
| 1982 | 529,890 | 27,826 | 5.5 |
| 1983 | 558,635 | 28,745 | 5.4 |
| 1984 | 589,038 | 30,403 | 5.4 |
| 1985 | 620,475 | 31,437 | 5.3 |
| 1986 | 652,968 | 32,493 | 5.2 |
| | | Average Growth Rate = | 5.7 |

WINTER PEAK DEMAND PERIODS

| | | | |
|---|---|---|---|
| 1977-78 | 360,447 | -- | - |
| 1978-79 | 383,688 | 23,241 | 6.4 |
| 1979-80 | 408,154 | 24,466 | 6.4 |
| 1980-81 | 433,614 | 25,460 | 6.2 |
| 1981-82 | 457,811 | 24,197 | 5.6 |
| 1982-83 | 482,896 | 25,085 | 5.5 |
| 1983-84 | 510,252 | 27,356 | 5.7 |
| 1984-85 | 539,049 | 28,797 | 5.6 |
| 1985-86 | 569,449 | 30,400 | 5.6 |
| 1986-87 | 599,666 | 30,217 | 5.3 |
| | | Average Growth Rate = | 5.8 |

1/ Non-coincident total of demands projected by the nine Regional Electric Reliability Councils in their April 1, 1977 responses to FPC Order 383-4.

of particulates from flue gases, and cooling towers add to the auxiliary power requirements of fossil-fuel generating units. The additional auxiliary power needed by generating units does not appear in the load forecasts, because the forecasts include only customer requirements and transmission and distribution losses. But the same type of additional power, when used by customers of a utility, does appear as a load requirement. For the Tennessee Valley Authority's (TVA) system, for instance, "it is expected that 7 percent of industrial electricity consumption will be utilized for pollution control devices among the 50 large TVA-served industries which account for 20 percent of area load."

## Energy Forecasts

Electric energy represents the total amount of electricity used, as differentiated from the demand (rate of use of electricity). The total annual electric energy requirement projected for each council area for the period 1977-1986 is listed in Table 4. Each council area of course has different geographic, industrial and demographic characteristics that result in differing uses of electric power and different annual growth rates. The total U.S. annual net energy requirements projected for 1977-1986 are shown in Table 5. Council load and capacity factors based on projected net energy and peak loads are given in Table 6.

## Generating Capability Projections

The construction of generating units is subject to the negative pressures of financing and environmental protection, as well as delays for various causes, and therefore the actual installed capability will probably be less each year than that projected. The total installed capability of the contiguous U.S. as projected for the time of the summer and winter peak demands in the years 1977 through 1986 is listed in Table 7.

## Annual Coal Demand for New Units, 1976-1985

The updated information on new coal-fired units and their future coal requirements obtained through the FPC's regional offices is summarized, by state and geographic region, in Table 8. It shows that, as of October 1976, electric utilities intended to add 130 new coal-fired units with a total

# TABLE 4

## PROJECTED ANNUAL ELECTRIC ENERGY REQUIREMENTS FOR THE REGIONAL ELECTRIC RELIABILITY COUNCILS CONTIGUOUS UNITED STATES GIGAWATT-HOURS [1]

| | | | | | | NPCC [2] | | SERC | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | ECAR [5] | ERCOT | MAAC | MAIN | MARCA [2] | N.E. [3] | N.Y. [4] | FLORIDA | SOUTHERN | TVA | VACAR | SWPP | WSCC [2] |
| 1977 | 352,500 | 137,510 | 167,850 | 163,905 | 87,857 | 80,588 | 117,552 | 78,922 | 102,204 | 132,270 | 139,488 | 180,133 | 411,082 |
| 1978 | 372,500 | 147,980 | 176,390 | 173,489 | 94,574 | 84,959 | 120,654 | 83,911 | 110,964 | 141,930 | 149,639 | 132,118 | 437,779 |
| 1979 | 394,400 | 156,590 | 185,337 | 184,525 | 102,162 | 89,472 | 125,022 | 89,168 | 119,427 | 154,670 | 160,324 | 204,807 | 461,874 |
| 1980 | 418,300 | 165,911 | 194,646 | 195,610 | 109,194 | 94,372 | 129,096 | 94,698 | 128,382 | 167,740 | 172,393 | 219,706 | 489,303 |
| 1981 | 441,800 | 176,089 | 204,214 | 207,130 | 115,796 | 99,518 | 133,325 | 100,398 | 137,701 | 174,680 | 184,230 | 232,914 | 513,692 |
| 1982 | 466,800 | 186,966 | 213,717 | 219,327 | 123,612 | 104,941 | 138,756 | 106,067 | 149,084 | 182,020 | 196,229 | 247,859 | 540,443 |
| 1983 | 492,500 | 196,292 | 223,477 | 232,361 | 130,478 | 110,578 | 144,784 | 111,461 | 160,417 | 189,590 | 209,181 | 263,346 | 566,901 |
| 1984 | 520,500 | 207,739 | 233,593 | 246,003 | 138,898 | 116,570 | 150,624 | 116,610 | 171,425 | 198,010 | 222,532 | 279,753 | 594,891 |
| 1985 | 549,400 | 217,107 | 244,003 | 260,697 | 146,912 | 122,870 | 156,654 | 121,671 | 184,197 | 205,530 | 236,660 | 297,970 | 625,699 |
| 1986 | 579,900 | 227,445 | 254,136 | 275,970 | 155,453 | 129,454 | 162,305 | 126,740 | 197,679 | 214,190 | 251,318 | 316,471 | 654,770 |

1/ 1 gigawatt-hour = 1,000,000 kilowatt-hours.

2/ Includes only United States portion of Council.

3/ Total for the six New England states.

4/ New York Power Pool.

5/ Revised energy data for ECAR was obtained too late to be incorporated in this report. However the greatest change for any year would be only two tenths of one percent.

SOURCE: April 1, 1977 responses to Appendix A-1 of FPC Docket R-362, (Order 383-4) Item No. 1.

TABLE 5

PROJECTED ELECTRIC ENERGY GROWTH
AS REPORTED BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
APRIL 1, 1977 IN RESPONSE TO FPC ORDER 383-4
CONTIGUOUS UNITED STATES

| YEAR | NET ENERGY REQUIREMENT 1/ GWH 2/ | ANNUAL INCREASE GWH | ANNUAL INCREASE % |
|---|---|---|---|
| 1977 | 2,151,861 | - | - |
| 1978 | 2,286,997 | 141,090 | 6.3 |
| 1979 | 2,427,898 | 140,901 | 6.2 |
| 1980 | 2,579,351 | 151,453 | 6.2 |
| 1981 | 2,721,487 | 142,136 | 5.5 |
| 1982 | 2,875,821 | 154,334 | 5.7 |
| 1983 | 3,031,366 | 155,545 | 5.4 |
| 1984 | 3,197,148 | 165,782 | 5.5 |
| 1985 | 3,369,370 | 172,222 | 5.4 |
| 1986 | 3,545,831 | 176,461 | 5.2 |
| | | Average Growth Rate = | 5.7 |

1/ This is intended to be the sum of all actual loads and system transmission and distribution losses. It is the net "sendout" of all power plants.

2/ 1 gigawatt-hour = 1,000,000 kilowatt-hours.

## TABLE 6

ANNUAL LOAD FACTORS 1/ IN PERCENT
AS PROJECTED APRIL 1, 1977 BY THE REGIONAL RELIABILITY COUNCILS
CONTIGUOUS UNITED STATES
1977-1986

| YEAR | ECAR | ERCOT | MAAC | MAIN | MARCA | NPCC | | SERC | | | | SWPP | WSCC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | N.E. | N.Y. | FLORIDA | SOUTHERN | TVA | VACAR | | |
| 1977 | 67.3 | 56.9 | 58.7 | 55.6 | 56.8 | 60.5 | 62.2 | 57.4 | 58.5 | 65.2 | 60.7 | 55.4 | 66.7 |
| 1978 | 67.0 | 57.6 | 58.9 | 55.5 | 57.0 | 60.4 | 61.4 | 57.2 | 57.3 | 64.6 | 60.9 | 55.0 | 66.8 |
| 1979 | 67.0 | 57.6 | 59.1 | 55.5 | 57.5 | 60.4 | 61.2 | 57.2 | 56.9 | 64.9 | 61.0 | 54.9 | 66.8 |
| 1980 | 67.1 | 57.5 | 59.4 | 55.6 | 57.2 | 60.4 | 60.8 | 57.1 | 56.8 | 66.7 | 61.4 | 54.7 | 66.8 |
| 1981 | 67.2 | 57.7 | 59.7 | 55.7 | 56.6 | 60.4 | 60.8 | 57.2 | 56.5 | 66.3 | 61.7 | 54.5 | 66.6 |
| 1982 | 67.2 | 57.7 | 59.9 | 55.9 | 56.7 | 60.5 | 61.3 | 57.1 | 57.2 | 65.9 | 62.1 | 54.1 | 66.8 |
| 1983 | 67.2 | 57.5 | 60.1 | 56.0 | 56.5 | 60.5 | 61.6 | 56.9 | 57.5 | 65.5 | 61.9 | 53.6 | 66.8 |
| 1984 | 67.3 | 57.5 | 60.3 | 56.0 | 56.9 | 60.6 | 61.5 | 56.8 | 57.7 | 65.2 | 61.8 | 53.1 | 67.0 |
| 1985 | 67.3 | 57.3 | 60.5 | 56.1 | 56.9 | 60.6 | 61.9 | 56.8 | 58.3 | 64.6 | 61.7 | 53.1 | 67.0 |
| 1986 | 67.2 | 57.1 | 60.7 | 56.2 | 57.1 | 60.6 | 61.9 | 56.8 | 58.5 | 64.1 | 61.6 | 52.6 | 67.1 |

1/ Load Factor (%) = $\frac{\text{Annual Energy Requirement in MWh}}{8760 \times \text{Annual Peak Demand in MW}} \times 100$

NOTE: According to the Edison Electric Institute's "59th Electric Power Survey" dated April 1976, p. 14, the annual load factors of the total electric utility industry in the contiguous U.S. for 1973-1975 were: 1973 - 62.0
1974 - 61.2
1975 - 61.4

TABLE 7

PROJECTED GROWTH OF GENERATING CAPABILITY 1/
AT TIME OF SEASONAL PEAK DEMAND PERIODS
CONTIGUOUS UNITED STATES
1977-1986
MEGAWATTS

CAPABILITY AT TIME OF SUMMER PEAK

| YEAR | TOTAL U.S. CAPABILITY | ANNUAL INCREASE MW | ANNUAL INCREASE % |
|---|---|---|---|
| 1977 | 512,158 | -- | - |
| 1978 | 541,592 | 29,434 | 5.7 |
| 1979 | 566,688 | 25,096 | 4.6 |
| 1980 | 591,656 | 24,968 | 4.4 |
| 1981 | 620,586 | 28,930 | 4.9 |
| 1982 | 654,274 | 33,688 | 5.4 |
| 1983 | 689,447 | 35,173 | 5.4 |
| 1984 | 729,335 | 39,888 | 5.8 |
| 1985 | 760,141 | 30,806 | 4.2 |
| 1986 | 792,909 | 32,768 | 4.3 |
| | | Average Growth Rate | 5.0 |

CAPABILITY AT TIME OF WINTER PEAK

| | | | |
|---|---|---|---|
| 1977-78 | 529,431 | -- | - |
| 1978-79 | 556,635 | 27,204 | 5.1 |
| 1979-80 | 581,351 | 24,716 | 4.4 |
| 1980-81 | 610,120 | 28,769 | 4.9 |
| 1981-82 | 641,306 | 31,186 | 5.1 |
| 1982-83 | 672,788 | 31,482 | 4.9 |
| 1983-84 | 705,259 | 32,471 | 4.8 |
| 1984-85 | 743,862 | 38,603 | 5.5 |
| 1985-86 | 773,898 | 30,036 | 4.0 |
| 1986-87 | 811,992 | 38,094 | 4.9 |
| | | Average Growth Rate | 4.8 |

1/ Total of installed capabilities projected by the nine Regional Electric Reliability Councils in their April 1, 1977 responses to FPC Order 383-4. Excludes purchases and sales.

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TABLE 8

## STATE AND REGIONAL COAL REQUIREMENTS FOR NEW UNITS SCHEDULED FOR OPERATION BETWEEN 1976 - 1985

| STATE AND GEOGRAPHIC REGION | NEW COAL UNITS SCHEDULED FOR OPERATION BETWEEN 1976-1985 NO. OF UNITS | CAPACITY (MW) | INCREMENTAL COAL DEMAND IN 1980 (1000 TONS) | QUANTITY ASSURED BY CONTRACT (1000 TONS) | % OF DEMAND | TOTAL NEW COAL UNITS SCHEDULED FOR OPERATION BETWEEN 1976-1985 NO. OF UNITS | CAPACITY (MW) | TOTAL INCREMENTAL COAL DEMAND IN 1985 (1000 TONS) | QUANTITY ASSURED BY CONTRACT (1000 TONS) | % OF DEMAND |
|---|---|---|---|---|---|---|---|---|---|---|
| CONN | 0 | - | - | - | - | 0 | - | - | - | - |
| ME | 0 | - | - | - | - | 0 | - | - | - | - |
| MASS | 0 | - | - | - | - | 0 | - | - | - | - |
| N H | 0 | - | - | - | - | 0 | - | - | - | - |
| R I | 0 | - | - | - | - | 0 | - | - | - | - |
| VT | 0 | - | - | - | - | 0 | - | - | - | - |
| NEW ENGLAND REGIONAL TOTAL | 0 | - | - | - | - | 0 | - | - | - | - |
| N Y | 0 | 0 | 0 | 0 | 0.0 | 3 | 2400 | 5900 | 0 | 0.0 |
| P A | 4 | 3077 | 10300 | 7300 | 70.9 | 5 | 3877 | 12200 | 7300 | 59.8 |
| N J | 0 | - | - | - | - | 0 | - | - | - | - |
| MID ATLANTIC REGIONAL TOTAL | 4 | 3077 | 10300 | 7300 | 70.9 | 8 | 6277 | 18100 | 7300 | 40.3 |
| ILL | 5 | 1736 | 3145 | 2340 | 74.4 | 8 | 3236 | 6835 | 5925 | 86.7 |
| IND | 7 | 3698 | 10340 | 9990 | 96.6 | 11 | 5543 | 15460 | 8068 | 52.4 |
| MICH | 5 | 1081 | 2749 | 0 | 0.0 | 10 | 2735 | 8149 | 4000 | 49.1 |
| OHIO | 4 | 2090 | 4250 | 2550 | 60.0 | 9 | 4760 | 10150 | 4400 | 43.3 |
| WISC | 3 | 1457 | 3730 | 1230 | 33.0 | 6 | 2737 | 6470 | 1230 | 19.0 |
| EAST NORTH CENTRAL REGIONAL TOTAL | 24 | 10062 | 24214 | 16110 | 66.5 | 44 | 19011 | 47004 | 23623 | 50.3 |
| IA | 4 | 1497 | 5121 | 3340 | 65.2 | 7 | 2377 | 8021 | 3340 | 41.6 |
| KAN | 4 | 2225 | 6093 | 5493 | 90.2 | 7 | 3685 | 11690 | 10250 | 87.7 |
| MINN | 3 | 1860 | 5500 | 5500 | 100.0 | 5 | 3460 | 9400 | 6600 | 70.2 |
| MO | 4 | 1950 | 5150 | 5150 | 100.0 | 5 | 2550 | 5750 | 4950 | 86.1 |
| NEB | 6 | 2097 | 4411 | 3897 | 88.3 | 6 | 2097 | 6770 | 5937 | 87.7 |
| N D | 5 | 2368 | 13750 | 13750 | 100.0 | 10 | 4488 | 25699 | 25699 | 100.0 |
| S D | 0 | - | - | - | - | 0 | - | - | - | - |
| WEST NORTH CENTRAL REGIONAL TOTAL | 26 | 11997 | 40025 | 37130 | 92.8 | 40 | 18857 | 67330 | 56776 | 84.3 |
| DELA | 1 | 400 | 800 | 0 | 0.0 | 1 | 400 | 800 | 0 | 0.0 |
| FLOR | 2 | 904 | 987 | 987 | 100.0 | 4 | 1658 | 3870 | 1219 | 31.5 |
| GA | 1 | 896 | 1551 | 1551 | 100.0 | 5 | 4196 | 8751 | 5551 | 63.4 |
| MD | 0 | 0 | 0 | 0 | 0.0 | 1 | 800 | 1500 | 0 | 0.0 |
| N C | 1 | 720 | 1410 | 1339 | 95.0 | 3 | 2160 | 4464 | 1608 | 36.0 |
| S C | 1 | 280 | 463 | 463 | 100.0 | 3 | 840 | 1467 | 0 | 0.0 |
| W VA | 2 | 1252 | 1500 | 0 | 0.0 | 2 | 1252 | 3000 | 0 | 0.0 |
| D C | 0 | - | - | - | - | 0 | - | - | - | - |
| V A | 0 | - | - | - | - | 0 | - | - | - | - |
| SOUTH ATLANTIC REGIONAL TOTAL | 8 | 4452 | 6711 | 4340 | 64.7 | 19 | 11306 | 23792 | 8378 | 35.2 |
| ALA | 4 | 1786 | 1980 | 1082 | 54.6 | 6 | 3152 | 6398 | 3326 | 52.0 |
| KY | 5 | 2000 | 4810 | 3046 | 63.3 | 11 | 4840 | 13799 | 6574 | 47.6 |
| MISS | 4 | 1396 | 2286 | 1396 | 61.1 | 4 | 1396 | 3052 | 2162 | 70.8 |
| TENN | 0 | - | - | - | - | 0 | - | - | - | - |
| EAST SOUTH CENTRAL REGIONAL TOTAL | 13 | 5182 | 9076 | 5524 | 60.9 | 21 | 9388 | 23249 | 12062 | 51.9 |
| ARK | 3 | 1928 | 7260 | 7260 | 100.0 | 5 | 3328 | 12960 | 12960 | 100.0 |
| LA | 3 | 1610 | 3500 | 3500 | 100.0 | 5 | 2690 | 9709 | 9709 | 100.0 |
| OKLA | 6 | 2960 | 10046 | 10046 | 100.0 | 8 | 3660 | 11204 | 9001 | 80.3 |
| TEX | 18 | 9613 | 36307 | 34307 | 94.5 | 38 | 20966 | 90334 | 63673 | 70.5 |
| WEST SOUTH CENTRAL REGIONAL TOTAL | 30 | 16111 | 57113 | 55113 | 96.5 | 56 | 30644 | 124207 | 95343 | 76.8 |
| ARIZ | 8 | 2750 | 8085 | 5885 | 72.8 | 9 | 3080 | 9085 | 5885 | 64.8 |
| COLO | 5 | 1710 | 5415 | 5415 | 100.0 | 6 | 2210 | 7635 | 5905 | 77.3 |
| ID | 0 | 0 | 0 | 0 | 0.0 | 2 | 1000 | 1600 | 1600 | 100.0 |
| MONT | 2 | 1030 | 2000 | 1335 | 66.7 | 3 | 1730 | 7000 | 1335 | 19.1 |
| NEV | 1 | 117 | 365 | 365 | 100.0 | 6 | 2117 | 8746 | 7351 | 84.0 |
| N M | 2 | 792 | 3220 | 3220 | 100.0 | 4 | 1608 | 6485 | 5450 | 84.0 |
| UTAH | 3 | 1215 | 2400 | 2400 | 100.0 | 5 | 1715 | 5238 | 5238 | 100.0 |
| WYO | 1 | 1330 | 4600 | 3100 | 67.4 | 5 | 2130 | 7100 | 5600 | 78.9 |
| MOUNTAIN REGIONAL TOTAL | 24 | 8944 | 26085 | 21720 | 83.3 | 40 | 15590 | 52869 | 38364 | 72.6 |
| ORE | 1 | 500 | 400 | 400 | 100.0 | 1 | 500 | 1200 | 1200 | 100.0 |
| CALF | 0 | - | - | - | - | 0 | - | - | - | - |
| WASH | 0 | - | - | - | - | 0 | - | - | - | - |
| PACIFIC REGIONAL TOTAL | 1 | 500 | 400 | 400 | 100.0 | 1 | 500 | 1200 | 1200 | 100.0 |
| U.S.TOTAL | 130 | 60325 | 173924 | 147637 | 84.9 | 229 | 111573 | 357771 | 243046 | 67.9 |

Source: Status of Coal Supply Contracts for New Electric Generating Units 1976-1985, Federal Power Commission, January 1977.

capacity of 60,325 megawatts during the years 1976 through 1980. The national average unit size planned for that 5-year period is 464 megawatts. By 1980 the projected annual coal requirement will be 2.88 tons per kilowatt of new capacity, reflecting both a higher average capacity factor for the new units and a lower average heat content of coal to be used by the new units.

During the period 1981-1985, utilities plan to construct an additional 99 units with a total capacity of 51,248 megawatts, i.e., the average unit size will be 518 megawatts. The average annual coal requirement of units to be completed during the second half of the decade is 3.26 kkg (3.59 tons) of coal per kilowatt of new capacity, underscoring the significant shift to the low-Btu subbituminous coal from the Northern Great Plains Province (Montana and Wyoming) and to lignite from the Fort Union Region (North and South Dakota) and from Texas. The average size of all new units placed on stream during the entire decade will be 487 megawatts and their average annual coal requirement in 1985 will be 2.91 kkg (3.21 tons) per kilowatt capacity.

The total 1980 and 1985 coal demand by new coal-fired units and the portion of that demand which is already under contract, by state and geographic region, also are shown in Table 6. Thus, in 1980, almost 85 percent, or 133.9 million kkg (147.6 million tons), of the total projected demand of 157.8 million kkg (173.9 million tons) is already under long term contract. The portion of the 1985 coal demand already under contract declines to 67.9 percent of the total projected demand of 324.6 million kkg (357.8 million tons).

There are significant regional differences in the proportion of the total cost demand which is under contract. Generally, utilities in the western regions have a much higher proportion of their projected coal demand under contract than utilities in the eastern regions.

## Origin and Destination of Coal For New Units

Of the national total of 11,573 megawatts of new coal-fired capacity scheduled for service in 1976-1985, 58.8 percent will be located in states west of the Mississippi River. Except for relatively small quantities of coal which will be shipped westward from the Eastern Coal Region of the Interior Province, the new units in the west will depend amost entirely on bituminous and subbituminous coal and lignite produced west of the Mississippi. The data supplied by the utilities project that about 94 percent of the incremental coal produced

in the west will be used by new units in the west. Because of the lower average heat content of western coal, units in the west will use more than their proportionate share of the new coal, i.e., 58.8 percent of the new coal-fired capacity will require 68.7 percent of the total incremental tonnage.

The western region of the Northern Great Plains (NGP) will provide more of the incremental steam coal production in the next 10 years than any other region. Of the 324.6 million kkg (357.8 million tons) of coal demand projected for new coal-fired units, 128 million kkg (141 million tons) or 39.4 percent will be supplied from this region. As a result, in 1985 the NGP may account for one-quarter of all the coal used by electric utilities. In 1975 this region supplied 10 percent of the total. As can be seen from Figure 16, most of the coal production from the western region of the Northern Great Plains (NGP) will be going to adjacent areas of the country. The West South Central Region will receive 57.0 million kkg (62.8 million tons) from the NGP while 38.9 million kkg (42.9 million tons) will go to the West North Central Region. In 1975 the East North Central Region was the easternmost area to receive coal from the Northern Great Plains, but by 1985 a small tonnage will be shipped as far as the South Atlantic Region.

The four states comprising the Mountain Region--Colorado, Utah, Arizona, and New Mexico--will supply 10.8 percent of the coal requirements for new coal-fired units. In 1975, 5.3 percent of all electric utility steam coal came from these states. Most of the coal from this four-state region going to new units will remain within the area with many of the new units being mine-mouth operations.

Bureau of Mines (BOM) District #15 which includes Kansas, Texas, Missouri and part of Oklahoma will experience a rapid rate of growth in demand for its coal production. With 15 percent of the coal demand for new units being for BOM District #15 coal, this region will supply approximately 10 percent of all electric utility coal in 1985, compared to 3.9 percent in 1975. As can be seen from Figure 17 virtually all of this coal will stay within the region, with 96 percent of the total coal output from BOM #15 being consumed in Texas.

The Appalachian Region has traditionally been the Nation's major source of coal for electric power generation. Of the 430.5 million tons of coal delivered to electric utilities in 1975, 44.8 percent was Appalachian coal. Data for new coal-fired units coming on line from 1976 through 1985 show that

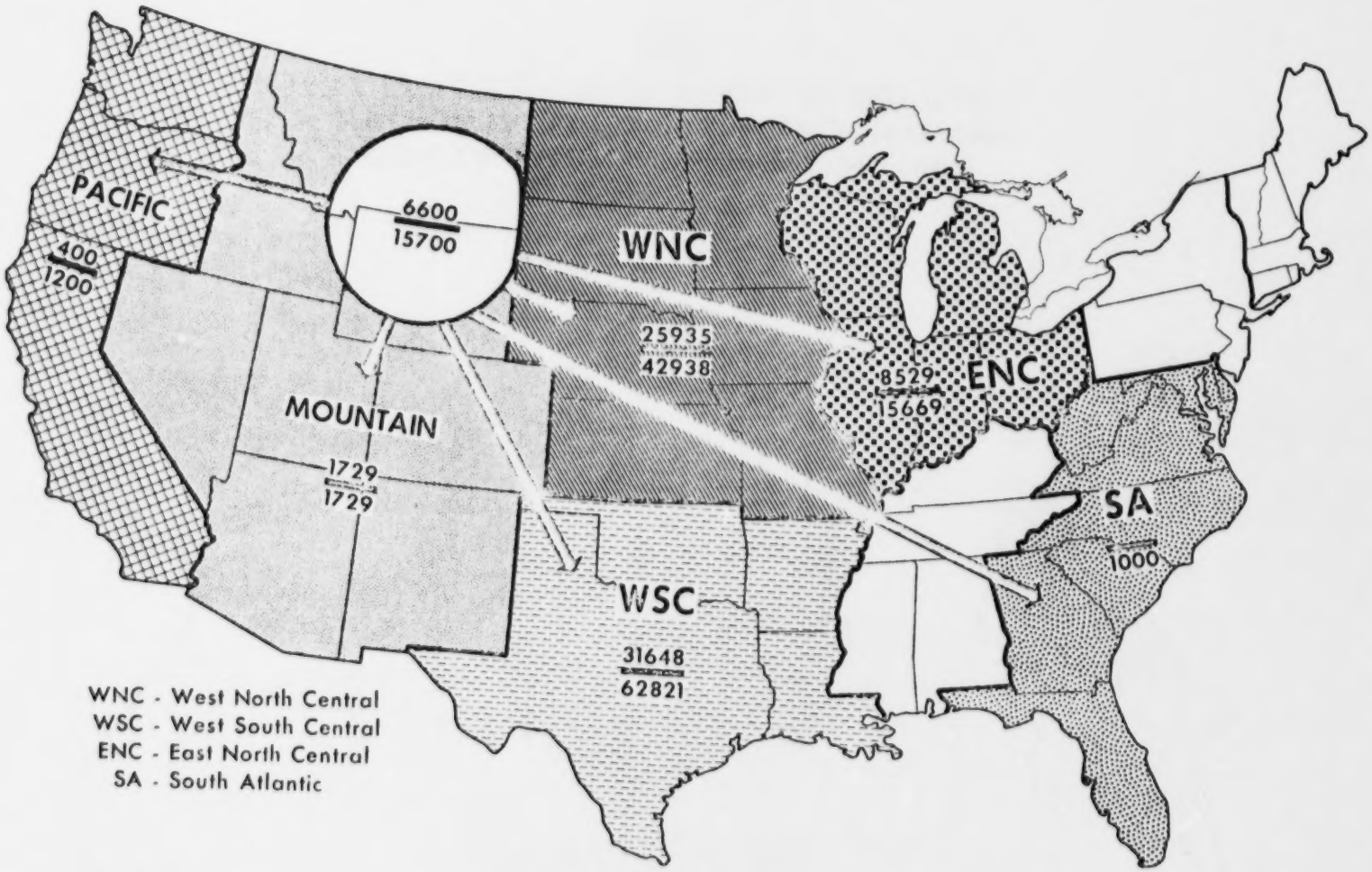


FIGURE 16

**FLOW OF COAL TO NEW GENERATING UNITS FROM THE WESTERN REGIONS OF THE NORTHERN GREAT PLAINS (IN 1000 TONS)**

**1980**
**1985**

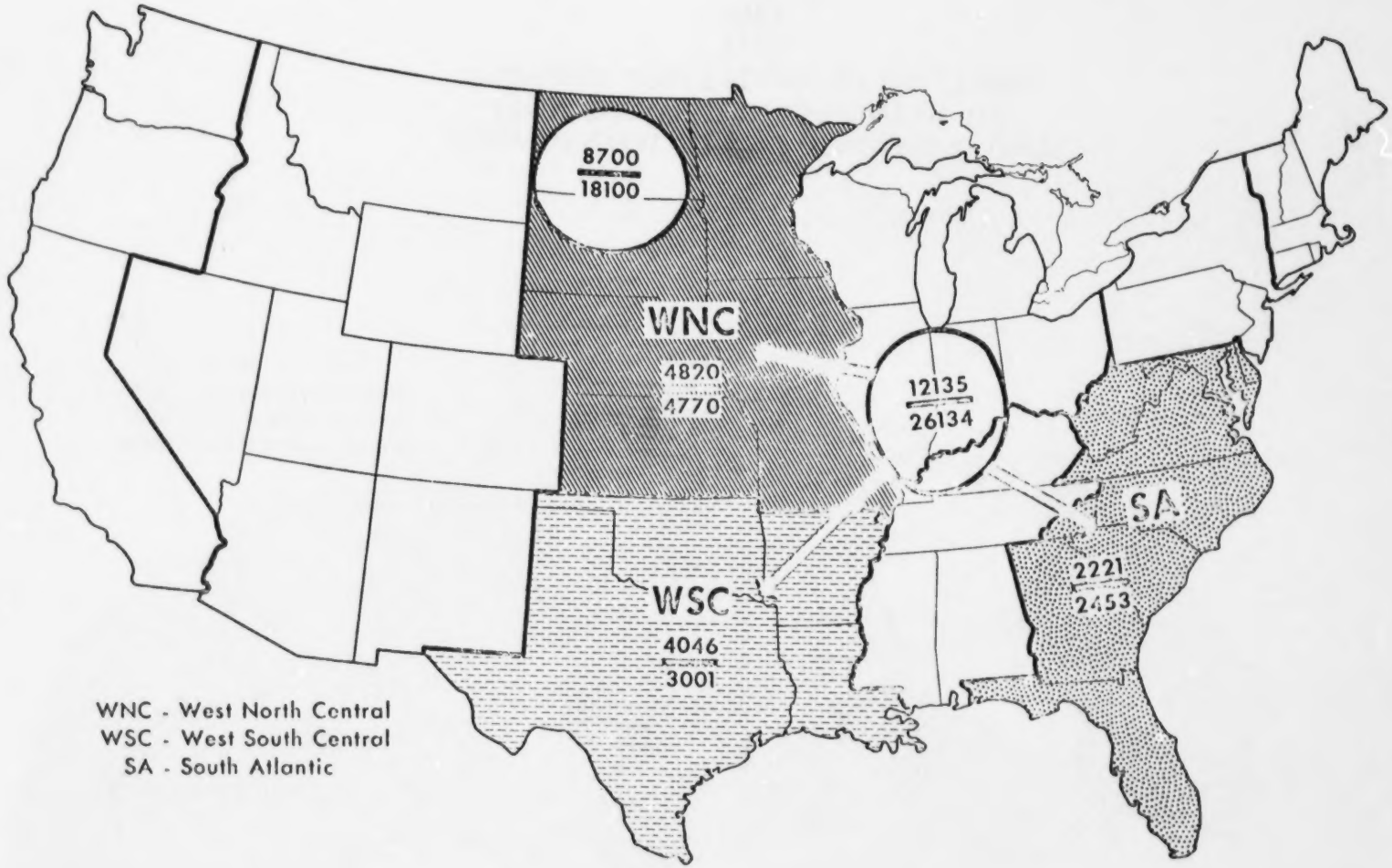


FIGURE 17

**FLOW OF COAL TO NEW GENERATING UNITS FROM THE EASTERN REGION (INTERIOR PROVINCE) AND THE FORT UNION REGION, (IN 1000 TONS)**

**1980**
**1985**

Appalachian will be the source for only 14.5 percent of the new units' coal requirements. Appalachia will still remain the largest source for steam coal in 1985, but its share of the total steam coal supply will drop to about 35 percent. As can be seen from Figure 6, 41.4 million tons of the total 52.2 million tons of Appalachian coal required by new units in 1985 will go to destinations in the East.

The Eastern Region of the Interior Province (see Figure 18), which supplied 29.4 percent of all the coal delivered to electric utilities in 1975, will supply 10.2 percent of the coal required for new units in 1985. As a result, by 1985 this region will supply only about 20 percent of the total coal used by old and new units of all utilities. Of the 33.0 million kkg (36.4 million tons) of coal from this region for new coal-fired units, 23.7 million kkg (26.1 million tons) will stay within the region, with relatively small shipments going to the West North Central, West South Central, and South Atlantic Regions.

Transport of Coal to New Units

Factors related to coal transport include the following:

a. Contractual agreements for transportation are not always concluded simultaneously with supply contracts, as evidenced by the proportions of total demand committed to supply and to transport contracts.

b. Nearly two-thirds of the 1985 coal demand by new units will be transported by rail. However, only a relatively small share of the total projected rail shipments, particularly from Appalachia to geographic regions in the eastern United States, is committed to contract. The level of contracts is also low for rail shipments from the Northern Great Plains, although not as low as from Appalachia.

c. The bulk of the shipments by barge will be from Appalachia, and to a lesser extent from the Interior Basin, to various regions in the east.

d. Shipments by truck and belt, reflecting the extent of mine-mouth plant developments, will take place almost entirely in the west.

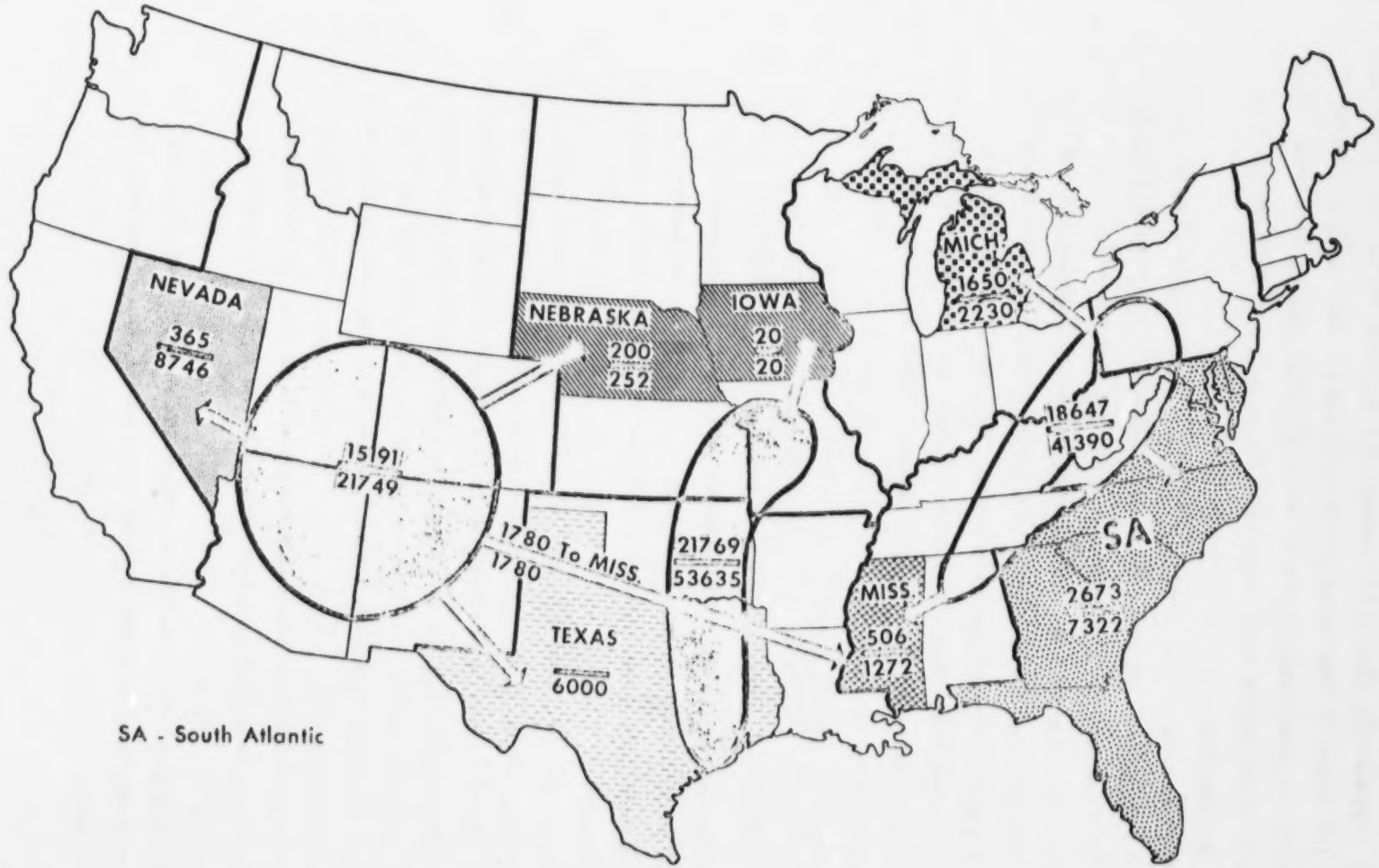


FIGURE 18

**FLOW OF COAL TO NEW GENERATING UNITS FROM THE APPALACHIAN REGION, FROM U.S. BUREAU OF MINES DISTRICT 15, AND FROM THE MOUNTAIN REGION (IN 1000 TONS)**

**1980**
**1985**

e. Coal deliveries by collier across the Great Lakes to new units in the East North Central Region will originate in the Northern Great Plains and the first leg of the shipments will be by rail.

f. Pipeline deliveries are projected for proposed coal-slurry shipments from the Rockies to plants in the Mountain Region.

## METHODOLOGY FOR DETERMINING COAL AVAILABILITY

### General Discussion

The following input data were used:

1) A realistic projection of the demand for coal by the electric utility industry... This was obtained from a FPC study, "Status of Coal Supply Contracts for New Electric Generating Units, 1976-1985", January 1977.
2) A reasonable assessment of the recoverable reserves... This was obtained from the Bureau of Mines study, "The Reserves of U.S. Coals by Sulfur Content", IC 8693.
3) A method for determining the potential for preparing coal reserves... This was obtained from the BOM study, "Sulfur Reduction Potential of U.S. Coals", RI 8118.
4) A projection of the electric power supply and demand... This was obtained from the FPC report, "Electric Power Supply and Demand, 1977-1986", May 1977, and summarized in the second section of this report.
5) An estimate of the potential demand for coal, if all units capable of conversion in the electric utility industry, did convert... This was obtained from the FPC study, "Factors Affecting - The Electric Power Supply, 1980-85", December 1976.
6) An accounting of the total FGD capacity in operation at the present time... This was obtained from the FPC report, "Annual Summary of Cost and Quality of Electric Utility Plant Fuels, 1976", May 1977.

The following factors entered into the use of the above input data:

1) The recoverability factor for underground coal is assumed to be 50 percent and that for surface coal 85 percent.

2) The wash samples taken as part of the cleanability study are assumed to accurately represent the recoverable reserve potential and the coal preparation potential.
3) The reduction in yield and Btu recovery were not factored into the availability calculations.
4) Logistical, cost, contractual, and other relevant parameters were not factored into the availability calculations.
5) It was assumed that all of the sulfur in the coal goes out of the stack as $SO_2$.
6) A normal distribution of $SO_2$ emissions was assumed. A relative standard deviation (RSD( of 10 percent and a $3\sigma$ confidence level was used to characterize the sulfur variability for a 30-day averaging period. This is a simplistic assumption in view of the wide variability of sulfur, but it is useful until better data are available.

Significance of Factors

Factor (1) would have to be further examined for those regions of the country where the results indicate the possibility of limited availability of coal.

Factor (2) is important for the determination of the availability of coal at the different cleanability levels. Comparisons of raw coal sulfur contents between the reserve data and the wash samples are given in Tables 9 and 10.

The data contained in Table 9 indicate that the Northern Appalachian washability samples related fairly well with coal reserve data. As indicated, these are the coals with the greatest beneficiation attractiveness.

For the Southern Appalachian Region the washability data do not correlate too well with the reserve base data, for a sulfur content less than 1 percent. This is due to the fact that the washability samples included in the study were only from Kanawha and Logan counties in West Virginia. The coals in this area are known to be of low sulfur content as mined.

The low sulfur comparison for the Western Region is given in Table 10. The poor correlation is not critical for the results in the Western Region since the availability of raw coal is adequate to meet the demand.

TABLE 9

COMPARISON OF COAL RESERVE DATA
AND WASHABILITY DATA - APPALACHIAN
REGION

SULFUR CONTENT (WEIGHT PERCENT)

| | ≤1 | ≤3 |
|---|---|---|
| N. Appalachian | | |
| Reserve Data | 8.4 | 61.8 |
| Washed Samples | 8.5 | 56.5 |
| S. Appalachian (excluding Alabama) | | |
| Reserve Data | 63.7 | 98.2 |
| Washed Samples | 80.0 | 98.5 |

TABLE 10

WESTERN REGION RESERVES -
CUMULATIVE PERCENT OF TOTAL AND COMPARISONS WITH WASHABILITY DATA

MILLION SHORT TONS

CUMULATIVE TOTAL FOR SULFUR CONTENT ≤ 1.0 PERCENT

| STATE | DEEP | STRIP | TOTAL |
|---|---|---|---|
| Colorado | 6,751 | 724 | 7,475 |
| Montana | 63,464 | 38,182 | 101,646 |
| N. Dakota | ----- | 5,389 | 5,389 |
| N. Mexico | 1,894 | 1,681 | 3,575 |
| Utah | 1,916 | 52 | 1,968 |
| Woyming | 20,720 | 13,193 | 33,913 |
| TOTAL | 94,745 | 59,221 | 153,966 |

CUMULATIVE TOTAL FOR SULFUR CONTENT UP TO 3 PERCENT

| | | | |
|---|---|---|---|
| Colorado | 7,438 | 870 | 8,308 |
| Montana | 65,860 | 40,403 | 106,263 |
| N. Dakota | ---- | 15,983 | 15,983 |
| N. Mexico | 2,109 | 2,260 | 4,369 |
| Utah | 3,320 | 243 | 3,563 |
| Wyoming | 26,531 | 23,741 | 50,272 |
| TOTAL | 105,258 | 83,500 | 188,758 |

CUMULATIVE PERCENT OF TOTAL FOR ≤ 1 PERCENT SULFUR CONTENT - COMPARISON

| | |
|---|---|
| RESERVE DATA | 82 |
| WASHED SAMPLES | 50 |

Factors (3) and (4) imply that the results for those regions of the country that show little or no coal availability are bounded to reflect the actual situation accurately. Those regions showing sufficient coal availability would have to be further examined to determine the effect of both these factors on the actual quantity of coal arriving at the required destinations.

Factor (5) reflects the bituminous coal producing region accurately (95-100 percent sulfur to $SO_2$ conversion). The subbituminous coal producing regions (72 percent sulfur to $SO_2$ conversion) and the lignite coal producing regions (60-90 percent sulfur to $SO_2$ conversion) are affected as follows: the results for the Western region, which contains a substantial amount of subbituminous and lignite coals, are therefore bounded by Factor (5) to reflect the actual situation accurately.

Factor (6) is important with respect to the results obtained with the inclusion of the effects of sulfur variability. The assumptions stated are probably reasonable, however, the actual RSD will vary for each type of coal and it will not necessarily remain the same for continued deliveries of the same coal. Deviations from the assumed value cannot be predicted on the basis of regional considerations.

The manner in which these factors affect the calculations determining the availability of coal from the different regions in the country is summarized in Table 11. The No designation indicates that factors have no significant effect and the Table 1 results can be used directly, without further analysis, for that specific category. For example, the 0.172 kg/GJ (0.4) standard cannot be met in any region. No further investigation is required to firm up this result. However, the Further Investigation designation for the Western 0.34 kg/GJ (0.8) category (Factor 4) implies that although it appears that coal is available, the problem of the coal getting from origin to destination also should be studied.

Two additional points should be noted:

1) All the projected available coal reserves were assumed to be available for use by the electric utility industry. At present, the electric utilities consume approximately 70 percent of the total coal production in the United States. If this ratio continued

TABLE 11

THE SIGNIFICANCE OF THE CALCULATION FACTORS
ON THE DETERMINATION OF COAL AVAILABILITY *

SIGNIFICANCE

| REGION | $SO_2$ | FACTORS | | | | |
|---|---|---|---|---|---|---|
| | | COAL RECOVERY 1 | WASH-ABILITY 2 | BTU RECOVERY 3 | OTHER ITEMS 4 | $S \rightarrow SO_2$ 5 |
| EASTERN | 1.2 | NO | NO | NO | NO | NO |
| | 0.8 | FI | FI | FI | FI | NO |
| | 0.4 | NO | NO | NO | NO | NO |
| EASTERN - MIDWEST | 1.2 | FI | FI | FI | FI | NO |
| | 0.8 | NO | NO | NO | NO | NO |
| | 0.4 | NO | NO | NO | NO | NO |
| WESTERN - MIDWEST | 1.2 | NO | NO | NO | NO | NO |
| | 0.8 | NO | NO | NO | NO | NO |
| | 0.4 | NO | NO | NO | NO | NO |
| WESTERN | 1.2 | NO | NO | NO | FI | NO |
| | 0.8 | NO | NO | NO | FI | NO |
| | 0.4 | NO | NO | NO | NO | NO |

* The significance of Factor 6, sulfur variability, cannot be established regionally

FI - FURTHER INVESTIGATION DESIRABLE

NO - NO SIGNIFICANT EFFECT

into the 1985 period, then all the results of this study should be reduced by 30 percent to reflect the use of coal in other sectors. Of course, as stated previously, the years of coal availability numbers are not intended to accurately reflect actual lifetimes of reserves.

2) The input data of the regional coal demand projections included heat content considerations. However, if one were tempted to ignore regional demarcations and consider coal availability for the entire United States as a whole unit, then variations in heat content should be factored into the calculations. The lower Btu content of the Western coals means that more coal is required to satisfy the total Btu requirements. The results in this study concerning "The Entire United States" do not take into account the reduced heat content factor, and are therefore overly optimistic. However, this again reinforces the need for FGD or a comparable control technique as discussed previously.

Basic Calculations

The calculations were performed for the four (4) major coal producing regions: Eastern, Eastern Midwest, Western Midwest, and Western. In addition, a composite calculation was performed considering the Entire United States as one whole region.

Three (3) levels of coal preparation were considered: raw coal, coal crushed to 3.8 cm (1.5 in) top size with a Btu recovery greater than or equal to 90 percent, and coal crushed to 0.117 (14 mesh) top size with a Btu recovery greater than or equal to 50 percent.

In addition calculations were performed for cleaned coal combined with FGD. The FGD was applied to 100 percent of the flue gas and had a 90 percent removal efficiency.

Four (4) $SO_2$ emission standards were considered: 1.81, 0.52, 0.34, and 0.17 kg $SO_2$ per GJ (2.0, 1.2, 0.8, and 0.4 lb $SO_2$ per million Btu).

The following is the calculation procedure:

1. The coal reserve was obtained from Document IC 8693.
2. The appropriate mining recovery factor was applied.
3. The percentage of this recoverable coal reserve, which can be cleaned to each $SO_2$ level, was read from one of the appropriate graphs (Figures 19-25) which was obtained from Document RI 8118.
4. The appropriate percentage was applied to the recoverable coal reserves. This yielded the total available coal tonnage for compliance with a given emission standard.
5. The projected 1985 coal demand by region was obtained from the FPC study, as tabulated in Table 4 of this report.
6. The total tonnage available was divided by the annual coal demand. This yielded the number of years that coal is available.

To conclude consideration of the variability of the sulfur content in coal, the following basic steps were employed in the calculation:

1) $\mu + 3\sigma$ = e.s., where

$\mu$ = mean value

$\sigma$ = standard deviation

$3\sigma$ = 99.87% point

e.s. = emission standard.

For RSD = 10 percent, the following tabulation gives the means $SO_2$ emission required to meet given emission standard.

| e.s., lb $SO_2/10^6$ Btu | $\mu$, lb $SO_2/10^6$ Btu |
|---|---|
| 2.0 | 1.54 |
| 1.2 | 0.92 |
| 0.8 | 0.62 |
| 0.4 | 0.31 |

3) The curves obtained using average sulfur content (Figures 4,6,8,10, and 12) were then used to obtain the new points. For example, for an emission standard of 1.2, the 0.92 point was used to obtain the coal availability information. The data obtained from these figures were then used to produce the Bar Chart (Figure 3) and the curves in Figures 5,7,9,12, and 13.

For example, for the Eastern Region, there are 220 years of coal available (Table 12) if there were no $SO_2$ emission regulations. The imposition of a 0.17 kg $SO_2$ per GJ (0.4 lb $SO_2$ per $10^6$ Btu) standard would drop this availability to 0 years (Table 16, continued), even if PCC were used. However, if FGD were used, this would make a minimum of 135 years of coal available (Table 16, continued) and allow compliance with the 0.17 (0.4) standard.

TABLE 12. RAW COAL AVAILABILITY[(a)]

| Region | Recoverable Reserves $10^6$ Tons | 1985 Utility Demand $10^6$ Tons | Maximum Years Available* Years |
|---|---|---|---|
| Entire U.S. | 259,798 | 788.3 | 330 |
| Eastern | 57,631 | 262.5 | 220 |
| Eastern Midwest | 50,687 | 162.8 | 312 |
| Western Midwest | 10,699 | 70.5 | 152 |
| Western | 140,781 | 274.5 | 512 |

* Based on 1985 Utility Demand Level

(a) Source: "Status of Coal Supply Contracts for New Electric Generating Units, 1976-1985", Federal Power Commission, January 1977.

TABLE 13

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING AND NEW)

THE ENTIRE UNITED STATES

| Level of Coal Preparation | STANDARD - LB $SO_2/10^6$ BTU | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2.0 Recoverable Reserves | | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| RAW COAL | 23 | 59,754 | 14 | 36,372 | 2 | 5,196 | 0 | 0 |
| 1.5",>90% Btu recovery* | 36 | 93,527 | 24 | 62,352 | 4 | 10,392 | 0 | 0 |
| 14 Mesh,>50% Btu recovery* | 48 | 124,703 | 32 | 83,135 | 7 | 18,186 | 0 | 0 |

1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
788.3 x $10^6$ TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

| | | | | |
|---|---|---|---|---|
| RAW COAL | 76 YRS | 46 YRS | 7 YRS | 0 YRS |
| 1.5",>90% Btu recovery | 119 YRS | 79 YRS | 13 YRS | 0 YRS |
| 14 Mesh,>50% Btu recovery | 158 YRS | 105 YRS | 23 YRS | 0 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 14

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

THE ENTIRE UNITED STATES

STANDARD - LB $SO_2/10^6$ BTU

| Level Of Coal Preparation | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
|---|---|---|---|---|---|---|
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| RAW COAL | 98 | 254,602 | 83 | 215,632 | 43 | 111,713 |
| 1.5",>90% Btu recovery* | 99 | 257,200 | 98 | 254,602 | 66 | 171,467 |
| 14 Mesh, >50% Btu recovery* | 100 | 259,798 | 99 | 257,200 | 87 | 226,024 |

1985 DEMAND FROM ALL UNITS (EXISTING PLUS NEW)
788.3 x $10^6$ TONS ANNUALLY

| | YEARS OF AVAILABLE SUPPLY ** FROM RECOVERABLE RESERVES | | |
|---|---|---|---|
| RAW COAL | 323 YRS | 274 YRS | 142 YRS |
| 1.5",>90% Btu recovery | 326 YRS | 323 YRS | 218 YRS |
| 14 Mesh, >50% Btu recovery | 330 YRS | 326 YRS | 287 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 15

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)

EASTERN REGION

| Level Of Coal Preparation | STANDARD - LB $SO_2/10^6$ BTU | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2.0 | | 1.2 | | 0.8 | | 0.4 | |
| | Recoverable Reserves | | Recoverable Reserves | | Recoverable Reserves | | Recoverable Reserves | |
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| N. Appalachia | | | | | | | | |
| RAW COAL | 15 | 5,472 | 4 | 1,459 | 1 | 365 | 0 | 0 |
| 1.5", 90% Btu recovery* | 35 | 12,768 | 12 | 4,378 | 2.5 | 912 | 0 | 0 |
| 14 Mesh,>50% Btu recovery* | 70 | 25,536 | 31 | 11,309 | 2.5 | 912 | 0 | 0 |
| S. Appalachia (Except Alabama) | | | | | | | | |
| RAW COAL | 80 | 16,095 | 35 | 7,042 | 3.5 | 704 | 0 | 0 |
| 1.5", 90% Btu recovery* | 90 | 18,107 | 50 | 10,060 | 3.5 | 704 | 0 | 0 |
| 14 Mesh,>50% Btu recovery* | 100 | 20,119 | 63 | 12,675 | 3.5 | 704 | 0 | 0 |
| Alabama | | | | | | | | |
| RAW COAL | 60 | 620 | 30 | 310 | 8 | 83 | 0 | |
| 1.5",>90% Btu recovery* | 65 | 671 | 30 | 310 | 8 | 83 | 0 | 0 |
| 14" Mesh,>50% Btu recovery* | 100 | 1,032 | 40 | 413 | 8 | 83 | 0 | 0 |

TABLE 15 (Continued)

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING AND NEW)

EASTERN REGION

| Level of Coal Preparation | STANDARD - LB $SO_2/10^6$ BTU | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2.0 Recoverable Reserves | | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
| Entire Region | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| RAW COAL | | 22,187 | | 8,811 | | 1,152 | | 0 |
| 1.5",>90% Btu recovery* | | 31,546 | | 14,748 | | 1,699 | | 0 |
| 14 Mesh,>50% Btu recovery* | | 46,688 | | 24,397 | | 1.699 | | 0 |

REGIONAL 1985 DEMAND FRON ALL UNITS (EXISTING AND NEW)
262.5 x $10^6$ TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY** FROM RECOVERABLE RESERVES

| | | | | |
|---|---|---|---|---|
| RAW COAL | 85 YRS | 34 YRS | 4 YRS | 0 YRS |
| 1.5",>90% Btu recovery | 120 YRS | 56 YRS | 7 YRS | 0 YRS |
| 14 Mesh,>50% Btu recovery | 179 YRS | 93 YRS | 7 YRS | 0 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 16

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN REGION

STANDARD - LB $SO_2/10^6$ BTU

| Level Of Coal Preparation | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
|---|---|---|---|---|---|---|
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| N. Appalachia | | | | | | |
| RAW COAL | 99 | 36,115 | 85 | 31,008 | 43 | 15,686 |
| 1.5",>90% Btu recovery* | 100 | 36,480 | 99 | 36,115 | 77 | 28,090 |
| 14 Mesh,>50% Btu recovery* | 100 | 36,480 | 100 | 36,480 | 91 | 33,197 |
| S. Appalachia (Except Alabama) | | | | | | |
| RAW COAL | 100 | 20,119 | 100 | 20,119 | 94 | 18,912 |
| 1.5",>90% Btu recovery* | 100 | 20,119 | 100 | 20,119 | 100 | 20,119 |
| 14 Mesh,>50% Btu recovery* | 100 | 20,119 | 100 | 20,119 | 100 | 20,119 |
| Alabama | | | | | | |
| RAW COAL | 100 | 1,032 | 100 | 1,032 | 78 | 805 |
| 1.5",>90% Btu recovery* | 100 | 1,032 | 100 | 1,032 | 82 | 846 |
| 14 Mesh,>50% Btu recovery* | 100 | 1,032 | 100 | 1,032 | 100 | 1,032 |

TABLE 16 (Continued)

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN REGION

STANDARD - LB $SO_2/10^6$ BTU

| Level Of Coal Preparation | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
|---|---|---|---|---|---|---|
| Entire Region | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| Total RAW COAL | | 57,266 | | 52,159 | | 35,403 |
| 1.5",>90% Btu recovery* | | 57,631 | | 57,266 | | 49,055 |
| 14 Mesh,>50% Btu recovery* | | 57,631 | | 57,631 | | 54,348 |

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
262.5 x $10^6$ TONS ANNUALLY

| | YEARS OF AVAILABLE SUPPLY ** FROM RECOVERABLE RESERVES | | |
|---|---|---|---|
| RAW COAL | 219 YRS | 199 YRS | 135 YRS |
| 1.5",>90% Btu recovery* | 220 YRS | 216 YRS | 187 YRS |
| 14 Mesh,>50% Btu recovery* | 220 YRS | 220 YRS | 207 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 17

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)

EASTERN - MIDWEST REGION

| Level of Coal Preparation | STANDARD - LB $SO_2/10^6$ BTU | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2.0 Recoverable Reserves | | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| RAW COAL | 2. | 1,014 | 1. | 507 | 0. | 0 | 0 | 0 |
| 1.5",>90% Btu recovery* | 5.5 | 2,788 | 2. | 1,014 | 1. | 507 | 0 | 0 |
| 14 Mesh,>50% Btu recovery* | 12. | 6,082 | 4. | 2,028 | 2. | 1,014 | 0 | 0 |

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
162.8 x $10^6$ TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

| | | | | |
|---|---|---|---|---|
| RAW COAL | 6 YRS | 3 YRS | 0 YRS | 0 YRS |
| 1.5",>90% Btu recovery | 17 YRS | 6 YRS | 3 YRS | 0 YRS |
| 14 Mesh,>50% Btu recovery | 37 YRS | 12 YRS | 6 YRS | 0 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 18

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

EASTERN - MIDWEST REGION

STANDARD - LB $SO_2/10^6$ BTU

| Level Of Coal Preparation | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
|---|---|---|---|---|---|---|
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| RAW COAL | 98 | 49,673 | 78 | 39,536 | 10 | 5,069 |
| 1.5",>90% Btu recovery* | 100 | 50,687 | 100 | 50,687 | 32 | 16,220 |
| 14 Mesh,>50% Btu recovery* | 100 | 50,687 | 100 | 50,687 | 78 | 39,536 |

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
162.8 x $10^6$ TONS ANNUALLY

| | YEARS OF AVAILABLE SUPPLY** FROM RECOVERABLE RESERVES | | |
|---|---|---|---|
| RAW COAL | 305 YRS | 243 YRS | 31 YRS |
| 1.5",>90% Btu recovery | 311 YRS | 311 YRS | 100 YRS |
| 14 Mesh,>50% Btu recovery | 311 YRS | 311 YRS | 243 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

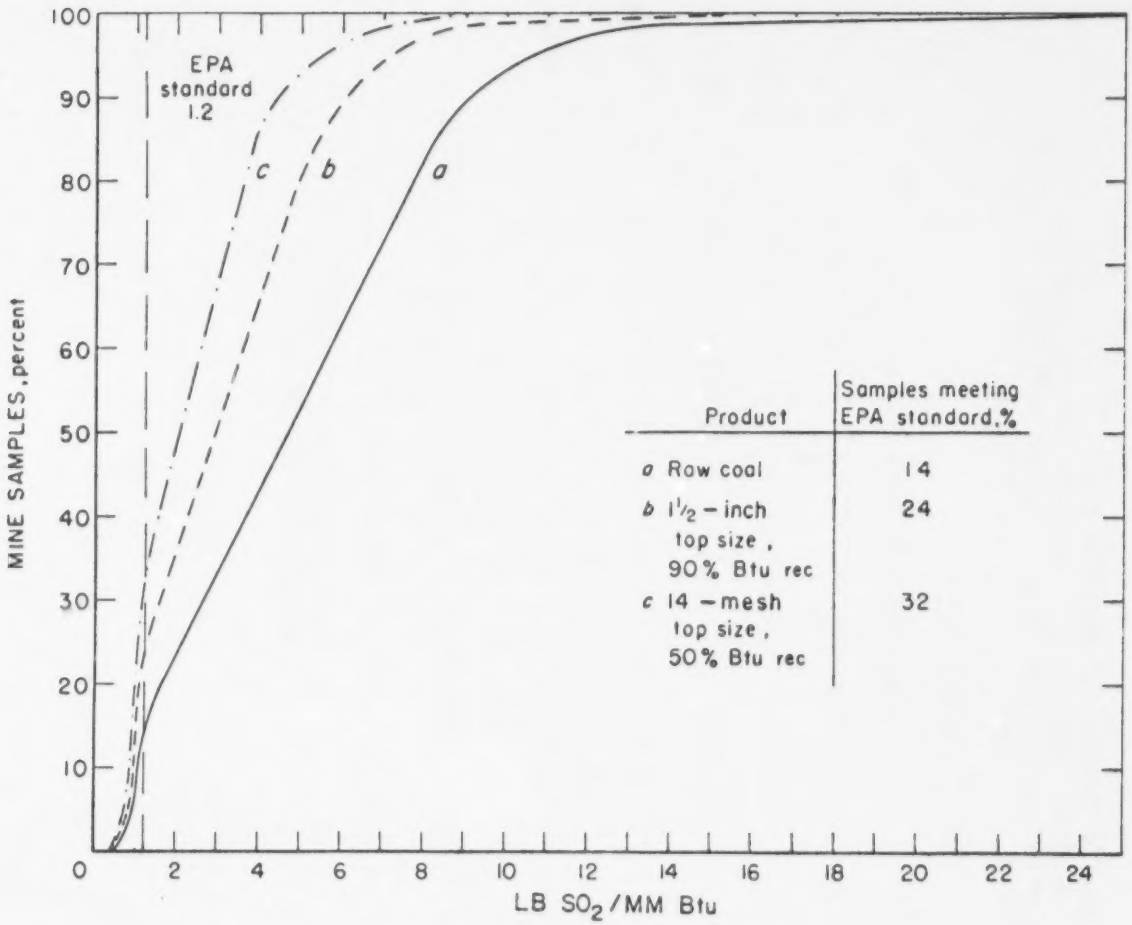


FIGURE 19

PERCENT OF ALL U.S. COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS $SO_2$/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

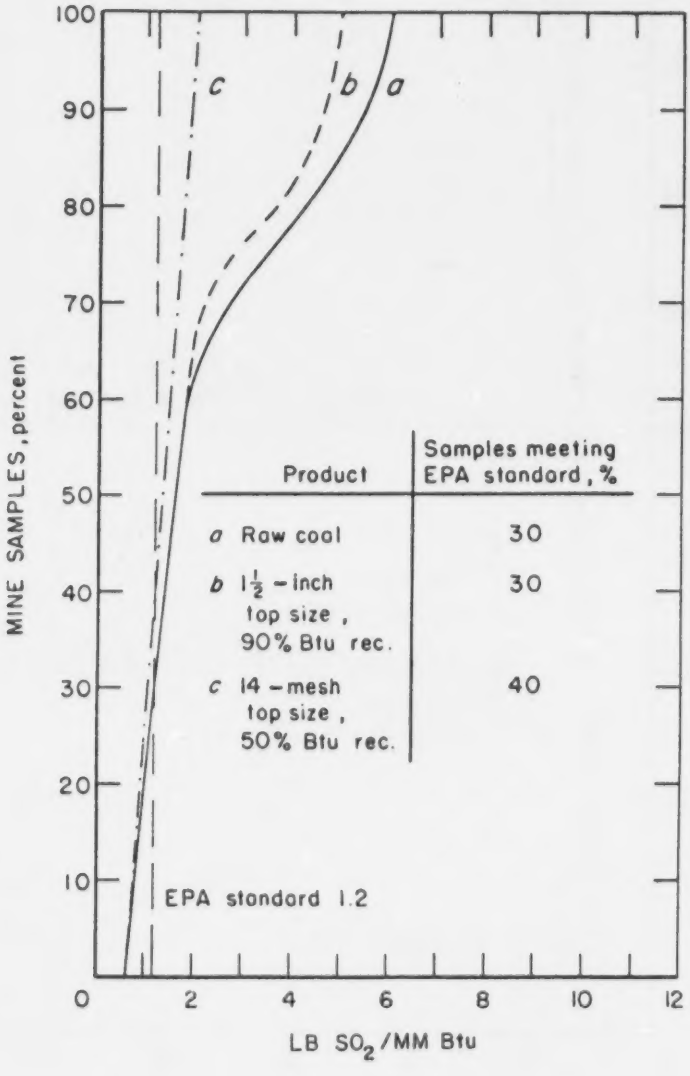
MINE SAMPLES, percent
LB $SO_2$/MM Btu
Product
Samples meeting EPA standard, %
a Raw coal 30
b 1½ – inch top size, 90% Btu rec. 30
c 14 – mesh top size, 50% Btu rec. 40
EPA standard 1.2

FIGURE 20

PERCENT OF ALABAMA REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS $SO_2$/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

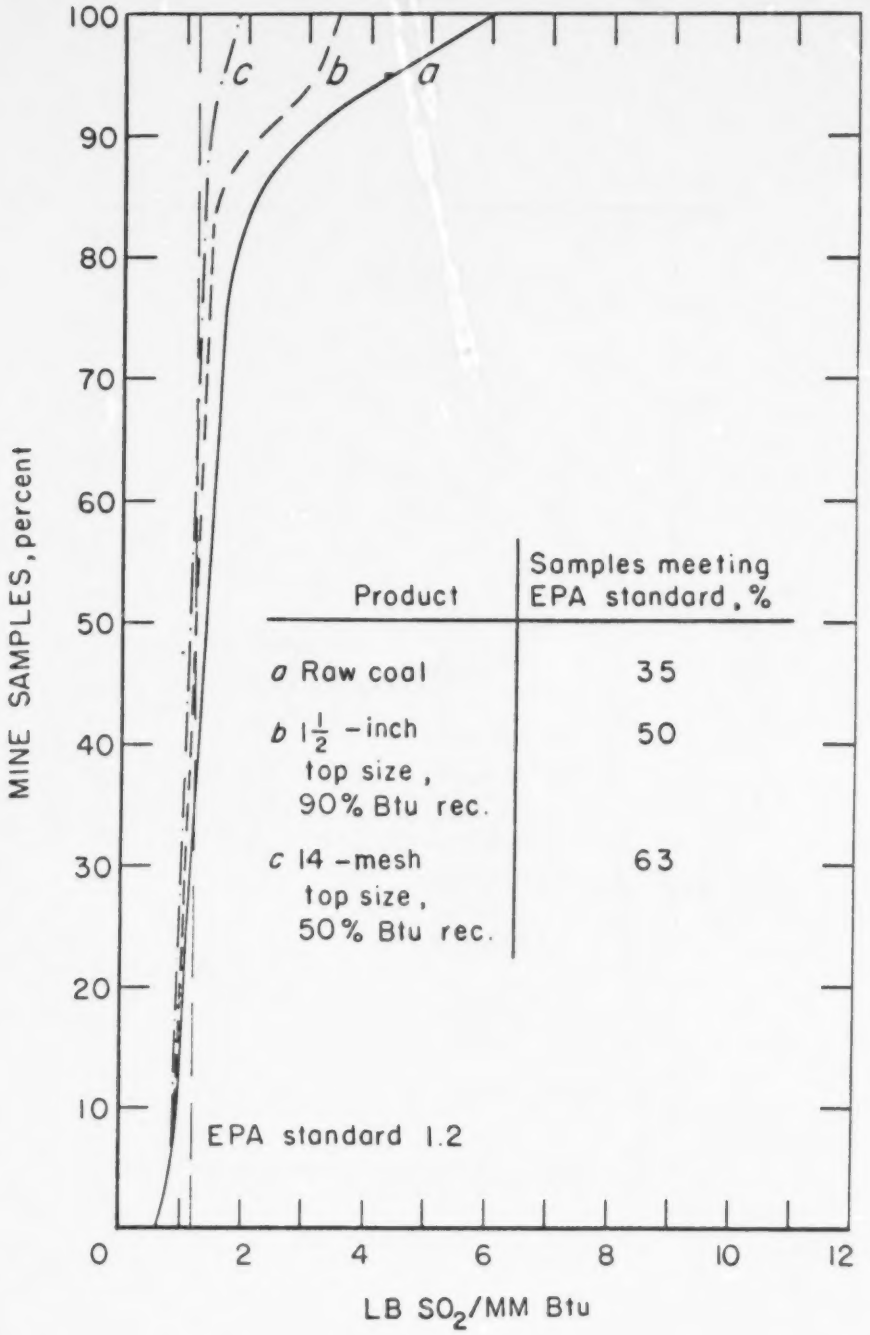


FIGURE 21

PERCENT OF SOUTHERN APPALACHIAN REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS $SO_2$/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

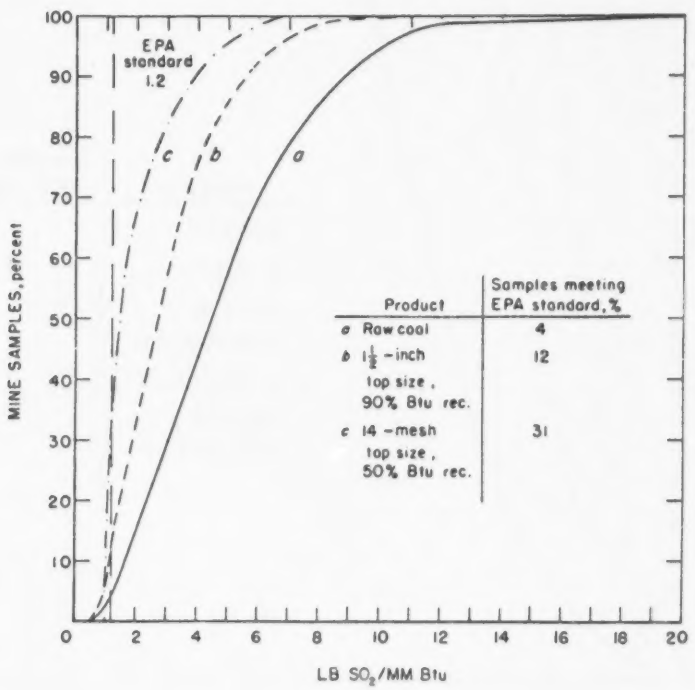
EPA standard 1.2
MINE SAMPLES, percent
LB $SO_2$/MM Btu
Product
Samples meeting EPA standard, %
a Raw coal 4
b 1½-inch top size, 90% Btu rec. 12
c 14-mesh top size, 50% Btu rec. 31

FIGURE 22

PERCENT OF NORTHERN APPALACHIAN REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS $SO_2$/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

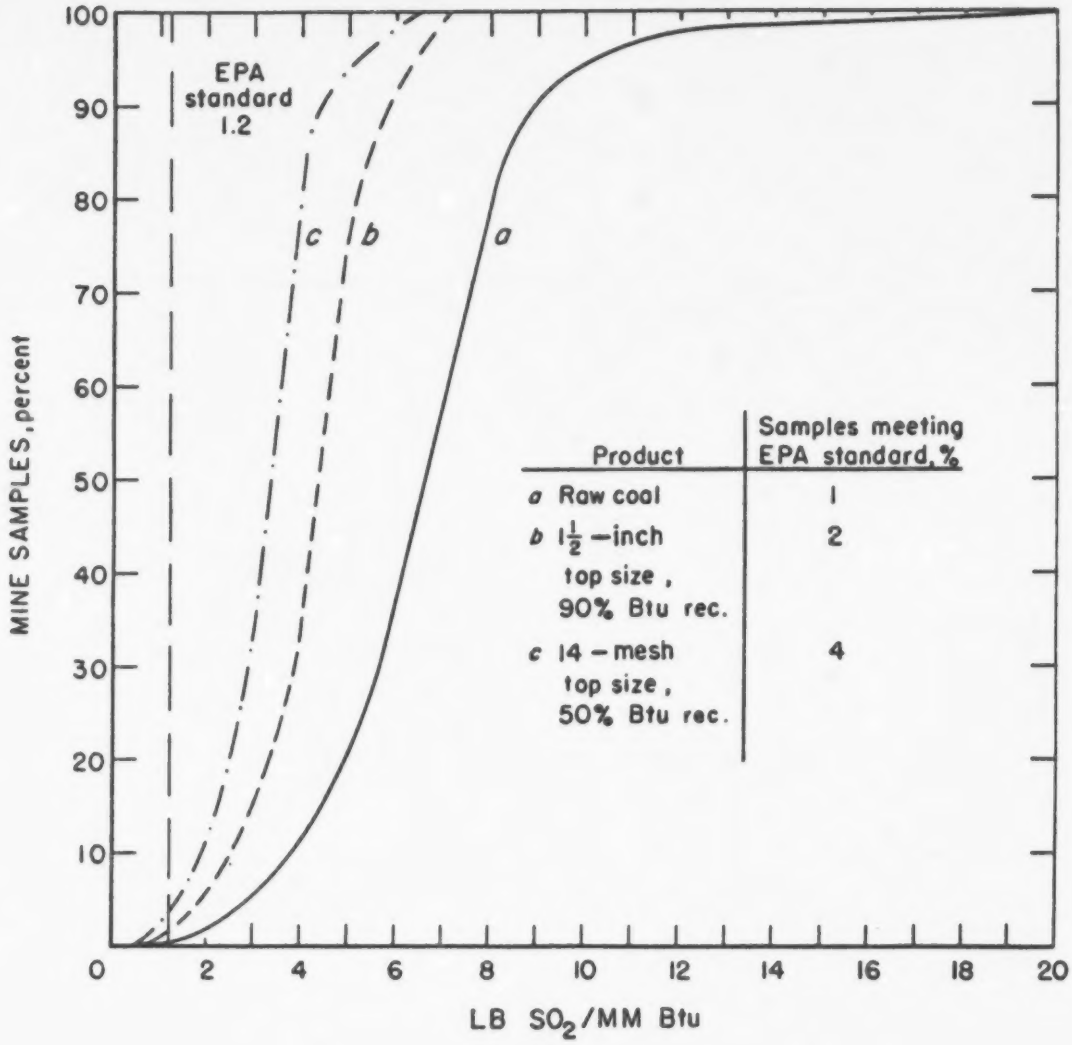


FIGURE 23

PERCENT OF EASTERN MIDWEST REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS $SO_2$/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

TABLE 19

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)

WESTERN - MIDWEST REGION

| Level of Coal Preparation | STANDARD - LB $SO_2/10^6$ BTU | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2.0 Recoverable Reserves | | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| RAW COAL | 5 | 535 | 2.5 | 267 | 0 | 0 | 0 | 0 |
| 1.5",>90% Btu recovery* | 8 | 856 | 5.5 | 588 | 0 | 0 | 0 | 0 |
| 14 Mesh,>50% Btu recovery* | 8 | 856 | 5.5 | 588 | 0 | 0 | 0 | 0 |

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
70.5 x $10^6$ TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

| | | | | |
|---|---|---|---|---|
| RAW COAL | 8 YRS | 4 YRS | 0 YRS | 0 YRS |
| 1.5",>90% Btu recovery | 12 YRS | 8 YRS | 0 YRS | 0 YRS |
| 14 Mesh,>50% Btu recovery | 12 YRS | 8 YRS | 0 YRS | 0 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 20

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN - MIDWEST REGION

STANDARD - LB $SO_2/10^6$ BTU

| Level Of Coal Preparation | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
|---|---|---|---|---|---|---|
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| RAW COAL | 82 | 8,774 | 40 | 4,280 | 10 | 1,070 |
| 1.5",>90% Btu recovery* | 93 | 9,951 | 82 | 8,774 | 16 | 1,712 |
| 14 Mesh,>50% Btu recovery* | 100 | 10,700 | 94 | 10,058 | 43 | 4,601 |

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
$70.5 \times 10^6$ TONS ANNUALLY

| | YEARS OF AVAILABLE SUPPLY ** FROM RECOVERABLE RESERVES | | |
|---|---|---|---|
| RAW COAL | 124 YRS | 61 YRS | 15 YRS |
| 1.5",>90% Btu recovery | 140 YRS | 124 YRS | 24 YRS |
| 14 Mesh,>50% Btu recovery | 152 YRS | 142 YRS | 65 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 21

RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING AND NEW)

WESTERN REGION

STANDARD - LB $SO_2/10^6$ BTU

| Level of Coal Preparation | 2.0 Recoverable Reserves | | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
|---|---|---|---|---|---|---|---|---|
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| RAW COAL | 90 | 126,703 | 70 | 98,547 | 25 | 35,195 | 1 | 1,408 |
| 1.5",>90% Btu recovery* | 100 | 140,781 | 94 | 132,334 | 37 | 52,089 | 1 | 1,408 |
| 14 Mesh,>50% Btu recovery* | 100 | 140,781 | 98 | 137,965 | 57 | 80,245 | 2 | 2,816 |

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
274.5 x $10^6$ TONS ANNUALLY

YEARS OF AVAILABLE SUPPLY **
FROM RECOVERABLE RESERVES

| | | | | |
|---|---|---|---|---|
| RAW COAL | 461 YRS | 359 YRS | 128 YRS | 5 YRS |
| 1.5",>90% Btu recovery | 512 YRS | 482 YRS | 189 YRS | 5 YRS |
| 14 Mesh,>50% Btu recovery | 512 YRS | 506 YRS | 292 YRS | 10 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

TABLE 22

RECOVERABLE RESERVES TO MEET THE NSPS,
FLUE GAS DESULFURIZATION (FGD) COMBINED WITH PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM ELECTRIC UTILITIES (EXISTING PLUS NEW)
FGD-90% REMOVAL EFFICIENCY, 100% OF GAS CLEANED

WESTERN REGION

STANDARD - LB $SO_2/10^6$ BTU

| Level Of Coal Preparation | 1.2 Recoverable Reserves | | 0.8 Recoverable Reserves | | 0.4 Recoverable Reserves | |
|---|---|---|---|---|---|---|
| | % | $10^6$ Tons | % | $10^6$ Tons | % | $10^6$ Tons |
| RAW COAL | 100 | 140,781 | 100 | 140,781 | 100 | 140,781 |
| 1.5",>90% Btu recovery* | 100 | 140,781 | 100 | 140,781 | 100 | 140,781 |
| 14 Mesh,>50% Btu recovery* | 100 | 140,781 | 100 | 140,781 | 100 | 140,781 |

REGIONAL 1985 DEMAND FROM ALL UNITS (EXISTING AND NEW)
274.5 x $10^6$ TONS ANNUALLY

| | YEARS OF AVAILABLE SUPPLY ** FROM RECOVERABLE RESERVES | | |
|---|---|---|---|
| RAW COAL | 512 YRS | 512 YRS | 512 YRS |
| 1.5",>90% Btu recovery | 512 YRS | 512 YRS | 512 YRS |
| 14 Mesh,>50% Btu recovery | 512 YRS | 512 YRS | 512 YRS |

* Tonnages do not reflect weight or Btu loss during cleaning.

** Based on 1985 demand level.

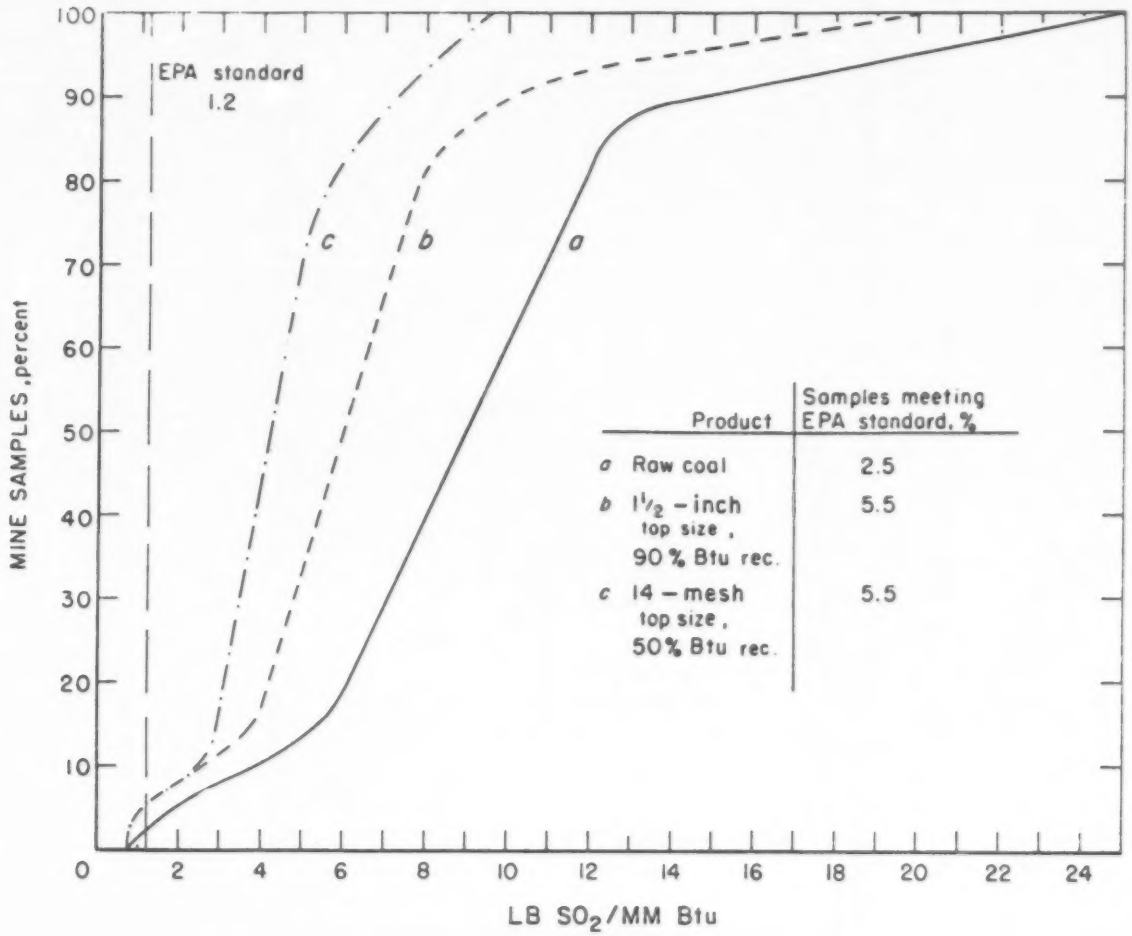


FIGURE 24

PERCENT OF WESTERN MIDWEST REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS $SO_2$/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED to 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

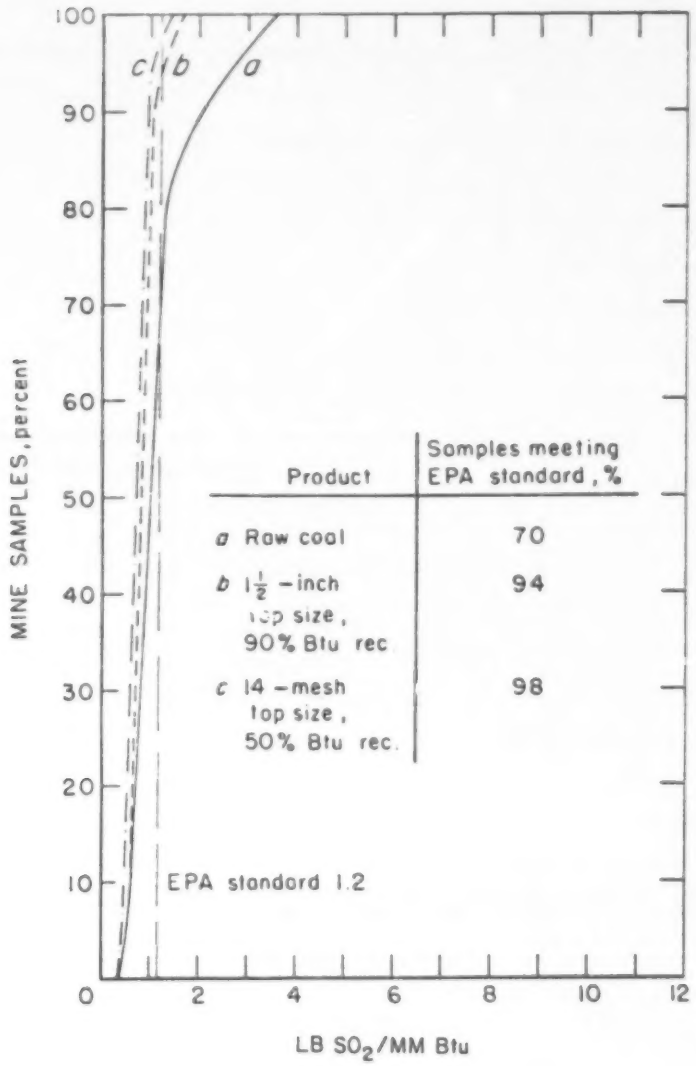


FIGURE 25

PERCENT OF WESTERN REGION COAL SAMPLES MEETING THE CURRENT EPA STANDARD OF 1.2 POUNDS $SO_2$/MM BTU WITH NO PREPARATION, CURVE a; COMPARED WITH THOSE CRUSHED TO 1-1/2-INCH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 90 PERCENT, CURVE b; AND THOSE CRUSHED TO 14-MESH TOP SIZE AT A BTU RECOVERY OF GREATER THAN OR EQUAL TO 50 PERCENT, CURVE c, AND SEPARATED GRAVIMETRICALLY.

SOURCE: U.S. Bureau of Mines, RI8118

## TECHNOLOGY, COST, AND ENVIRONMENT OVERVIEWS OF COAL CLEANING

Coal cleaning accomplishes the removal of slate, clay, carbonaceous shales, pyrite and rock aggregate. There are many processes for cleaning coal, each having its own benefits and disadvantages. These processes can be divided into two general categories, physical and chemical coal cleaning.

### Physical Coal Cleaning

Physical cleaning can be defined generally as the separation of waste or unwanted "refuse" material from coal by techniques based on the differences in the physical properties of coal and refuse. The most common physical property used to clean coal is density. Specific gravity ranges are generally as follows:

| | |
|---|---|
| coal | 1.2-1.7 |
| carbonaceous shale | 2.0-2.6 |
| gypsum, kaolin, calcite | 2.3-2.7 |
| pyrite | 5.0 |

Density separation is done using hydraulic jigs, concentrating tables, cyclones, dense medium vessels, or air classifiers. In such equipment ground coal is suspended in a fluid, and the refuse material falls to the bottom of the separating unit, whereas the cleaned coal will float or move to the top of the unit for removal. A related technique, froth flotation, additionally utilizes the surface properties of coal particles to advantage to enhance the separation. Physical cleaning will remove mineral sulfur, e.g., pyrite, which has a high density, but not organic sulfur, which is an integral part of the coal. The amount of mineral sulfur removed depends on the crystal size of the mineral sulfur. The smaller the crystals are, the smaller particle size the run of the mine (ROM) coal must be crushed to achieve effective separation. If the particle sizes of the mineral sulfur

and pulverized coal are not matched well, large amounts of coal will be lost with the refuse if a large fraction of the mineral sulfur is to be removed. As the coal is pulverized to smaller and smaller particle sizes, costs of pulverization rise quickly. These costs vary widely depending on the type of coal.

The Btu recovery rate of the cleaning process is usually based on the input heating value. The heating value of the coal lost in the refuse is counted as an energy loss. Physical cleaning generally has a Btu recovery of 80 to 95 percent of the ROM coal, with the largest losses associated with coal lost with the refuse, and, with the coal required to operate the thermal drier. One can expect physical cleaning to remove 35 to 70 percent of the mineral sulfur in ROM coals, depending on the amount of size reduction done and the many other physical characteristics of the coal.

Hoffman[1] has studied the costs of physically cleaning easily-cleaned northern Appalachian coals, presenting cost data for coals cleaned at a top size of 0.95 cm (3/8 inch), and high yield factors (a range of 85 to 95 percent of input product yield, weight basis). Other Appalachian coals generally have a 60 to 70 percent weight yield[2] and the associated costs would be higher on a cleaned-coal basis. Capital investment for a physical cleaning plant larger than 454 kkg (500 tons) per hour capacity at the mine mouth (a lower practical economic limit) can run between $9920 and $49,600 per kkg ($9,000 and $45,000 per short ton) per hour of capacity[2]. (The higher value, $49,600, includes rail spurs, and coal handling equipment normally associated with mine facilities costs.) The mean cost range is $16,500 to $19,800 per kkg ($15,000 to $18,000 per short ton) per hour capacity. These mean costs are incremental to mine facility costs, e.g., rail spurs, conveyors, etc. If one assumes the following:

1) 15 year capital write off,
2) 13 productive hours per day, 260 days per year operation,
3) interest rate of 10 percent,
4) 90 percent product yield, and
5) $19,800 per ton per hour of capacity capital cost,

one can expect a capital charge of $0.845 per kkg ($0.767 per ton) of ROM coal processed for a 454 kkg (500 short tons) per hour plant, and an operating

and maintenance cost of $0.72 to $0.94 per kkg ($0.65 to $0.80 per short ton) of ROM coal processed, depending on the site and coal specifics of the cleaning plant. The operating and maintenance cost includes an allowance for disposal costs of the refuse. Because of the loss of rejects material in cleaning, and because the heating value is an important factor in selling the cleaned coal, costs are usually reported in dollars per million Btu. If the coal is assumed to go from a ROM heating value of 25.58 MJ per kg (11,000 Btu per pound) to a product heating value of 27.91 MJ per kg (12,000 Btu per pound), with a ROM coal price of $19.80 per kkg ($18 per ton), and a 90 percent weight yield, the cost of cleaning would be calculated as follows:

$$\text{Raw Coal Cost} = \frac{\$19.80 \text{ per kkg}}{(25.58 \text{ MJ/kg})(1000 \text{ kg/kkg})} = \$0.774/\text{GJ}$$

$$\begin{aligned}\text{Cleaned Coal Cost} = \ & \$19.80 \text{ ROM coal cost} \\ & .84 \text{ capital charge} \\ & .94 \text{ O\&M cost} \\ & \$21.58 \text{ per kkg ROM coal}\end{aligned}$$

$$\frac{\$21.58}{0.9 \text{ yield}} = \$23.98/\text{kkg cleaned coal}$$

$$\frac{\$23.98/\text{kkg}}{(27.91 \text{ MJ/kg})(1000 \text{ kg/kkg})} = \$0.859/\text{GJ}$$

$$\text{Cleaning cost} = \$0.859 - \$0.774 = \$0.085/\text{GJ or } \$0.09/10^6 \text{ Btu}$$

$$\frac{\$19.57}{0.9 \text{ yield}} = \$21.74/\text{ton cleaned coal}$$

$$\frac{\$21.74/\text{ton } (10^6)}{(12{,}000 \text{ Btu/lb})(2000 \text{ lb/ton})} = \$0.906/10^6 \text{ Btu cleaned coal}$$

$$\text{Cleaning cost} = \$0.906 - \$0.818 = \$0.087/10^6 \text{ Btu}$$

This cost is for a plant using hydraulic jigs, washing tables, cyclones, froth flotation units, filters, screens, and mechanical and thermal driers. Using the cleaned coal as a basis, the cleaning cost is then $2.37 per kkg (2.09 per ton). If the cleaning yield is assumed to be much lower, e.g. 60 weight percent, the ROM heating value of the coal say 18.61 MJ per kg (8000 Btu per pound), and a ROM coal price of $11 per kkg ($10 per ton), the capital charges and operating and maintenance costs used above lead to a cleaned coal processing cost of $4.80 per product kkg ($4.27 per product short ton), and $0.172 per GJ ($0.178 per million Btu's). These figures do not include any profit for the operation.

It should be noted that other benefits accrue to the utility using cleaned coal in addition to sulfur reduction, such as: increased heating value and reduced ash content of the product, reduced transporation costs, reduced pulverizing costs, increased boiler capacity and availability, and savings in boiler maintenance costs. The value of these benefits should be considered when the cost-benefit of coal cleaning is evaluated for a specific utility application.

There are several other techniques that can be used in physical cleaning, e.g., magnetic separation of iron pyrite ($FeS_2$), oil agglomeration, and electrophoretic and electrostatic separation. Either for economic or processing reasons, these have not been developed sufficiently for detailed discussion in this report.

Physical coal cleaning reduces sulfur and ash content. Both enhance the environmental acceptability of burning the cleaned coal. However, physical cleaning has its own set of environmental problems. The refuse is usually gob piled. These piles can be a source of highly acid mine drainage, requiring a collection and lime treatment system for the drainage. Gob piles also can be sources of fugitive dust. All of the physical cleaning processes have various internal environmental problems. Table 23 gives generalized environmental problems for the various process technologies.

Chemical Cleaning

There are currently 25 chemical cleaning processes under active development and many more under conceptual development. Of these 25, only eight have any economic information published or available.

TABLE 23. PHYSICAL COAL CLEANING PROCESS ENVIRONMENTAL PROBLEMS

| TECHNOLOGY | PROBLEM | CONTROL METHOD |
|---|---|---|
| Jig, Launder, Cyclone, Table | Contaminated process water | Closed water cycle |
| Dense medium vessel and cyclone | Contaminated process water, dense media loss | Closed water cycle |
| Air classifier | Fugitive coal dust | Cyclone collector, bag house electrostatic precipitator (ESP) |
| Froth flotation | Contaminated process water, flotation reagents loss | Closed water cycle |
| Electrostatic | Fugitive coal dust | Cyclone collector, bag house, ESP |
| Electrophoretic | Contaminated process water | Closed water circuit |
| Magnetic | Contaminated process water | Closed water circuit |
| Oil agglomeration | Contaminated process water, fuel oils, tar oil in contact with water | Closed water and oil circuit |

Meyers/TRW Process. The Meyers process is the most highly developed chemical cleaning process. It has been studied by Dow Chemical, Bechtel, and Dynatech.[3,4,5] The process leaches -149 μm (-100 mesh) coal containing iron pyrite ($FeS_2$) with ferric sulfate ($Fe_2(SO_4)_3$), converting the pyrite to sulfuric acid, ferrous sulfate, and elemental sulfur, at moderate temperatures and pressures, 70 C to 120 C (160 F to 250 F), and 100 kN/$m^2$ to 550 kN/$m^2$, (15 to 80 psia), with long leaching times (5 to 10 hours). The process has no proven organic sulfur removal and TRW does not claim any. Elemental sulfur produced is solvent extracted or vaporized and recovered by condensation. Figure 26 indicates the layout unit processes involved in the Meyers process.

Dow Chemical[3] has done an extensive design and economics study of this process for a 420 kkg (380 short tons) per hour plant. Their total capital cost for this design was $145 million (mid-1975 dollars) plus or minus about 20 percent. This includes limited physical cleaning facilities for removal of rock aggregate and shales. Dow[6] feels that based on this design and 95 percent removal of pyritic sulfur, a cleaning cost of $11 to $15.50 per kkg ($10 to $14 per ton) of cleaned coal would be appropriate currently. Bechtel Corporation[4] has studied the economics of a 300 kkg (330 short ton) per hour plant suggesting a total capital cost of $131 million and a cleaning cost of $0.78 per GJ ($0.82 per million Btu's), or $20.90 per cleaned kkg ($19 per cleaned short ton). Both companies' costs contain no profit margins, and Dow's cost is based on cleaning a Pennsylvania Lower Kittanning coal. Bechtel's design is based on using a Pittsburgh A bituminous coal. Dow indicates that, based on their design, the process can achieve a 90 percent Btu recovery, while Bechtel indicates 98 percent Btu recovery.

The Meyers process may be one of the more troublesome chemical cleaning processes from an environmental standpoint. It uses organic solvents in contact with process wastes to extract the elemental sulfur. A portion of the solvent will be left in the cleaned coal. The waste products of the process, ferrous sulfate, sulfuric acid, and physical cleaning refuse, have to be disposed of properly with pH adjustment. This refuse is obviously much more acidic than just physical cleaning refuse alone. Internally, the process must use a closed water circuit with solvent recovery to avoid further effluent problems.

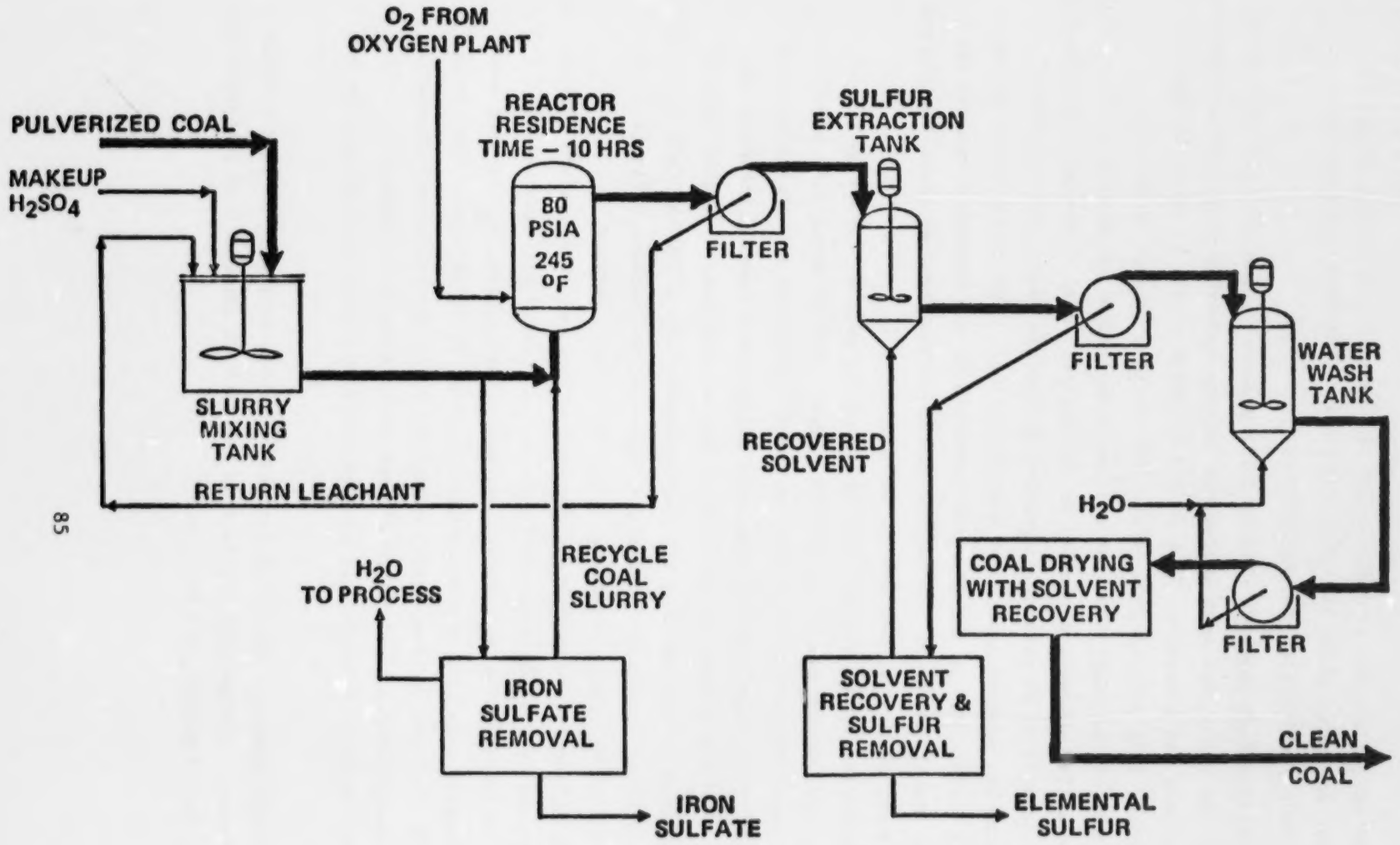


FIGURE 26. MEYERS/TRW PROCESS FLOW DIAGRAM

The Meyers process probably could be commercial in 5 to 6 years. An 8 ton per day pilot plant has been constructed. Information from this should help provide scale-up information.

Battelle Hydrothermal. The Battelle process[7] leaches -149 μm + 74 μm (-100 + 200 mesh) coal with sodium and calcium hydroxide solutions at elevated temperatures and pressures, 98 C to 170 C (200 F to 340 F) and 1.55 $MN/m^2$ to 17.25 $MN/m^2$ (225 psia to 2500 psia). The process removes up to 99 percent of the mineral sulfur and has demonstrated 24 percent to 72 percent organic sulfur removal, depending on the specific coal processed. Btu recovery ranges from 75 to 90 percent, depending on process operation. Figure 27 indicates the process layout and unit operations. The capital cost of the process suffers due to the elevated temperatures and pressures used in the system, and the need for leachant regeneration equipment to close the process water loop, preventing the loss of leachant.

Battelle currently feels that an operating cost of $19.80 to $27.50 per kkg ($18 to $25 per short ton) of cleaned coal or about $.95 per GJ ($1.00 per million Btu) is a good estimate[8] based on the regeneration of leachant, 0.25 hour leaching time, and processing a Lower Kittanning coal from 2.4 to 0.9 percent sulfur. Under these conditions a capital cost of $134 million to $145 million has been estimated for a 360 kkg (400 short tons) per hour plant, the cost depending on the coal to leachant ratio (2 to 1, or 3 to 1). No profit margin is included in these figures.

With leachant regeneration, internal process water loops are closed, so that the only water effluent is in the wet coal. Hydrogen sulfide ($H_2S$) is produced in the process, and protection against $H_2S$ leakage would be necessary both from a processing and safety point of view. The process is known to leach out many heavy metals in coal. Any effluents containing high concentrations of these metals may require special disposal.

The Battelle hydrothermal process could be commercialized in 4 to 6 years.

Hazen Process. The Hazen process[4], shown in Figure 28 is a totally dry process. The process reacts iron pyrite with gaseous iron pentacarbonyl:

$$3\ FeS_2 + Fe(CO)_5 \rightarrow 2\ Fe_2S_3 + 5\ C \quad .$$

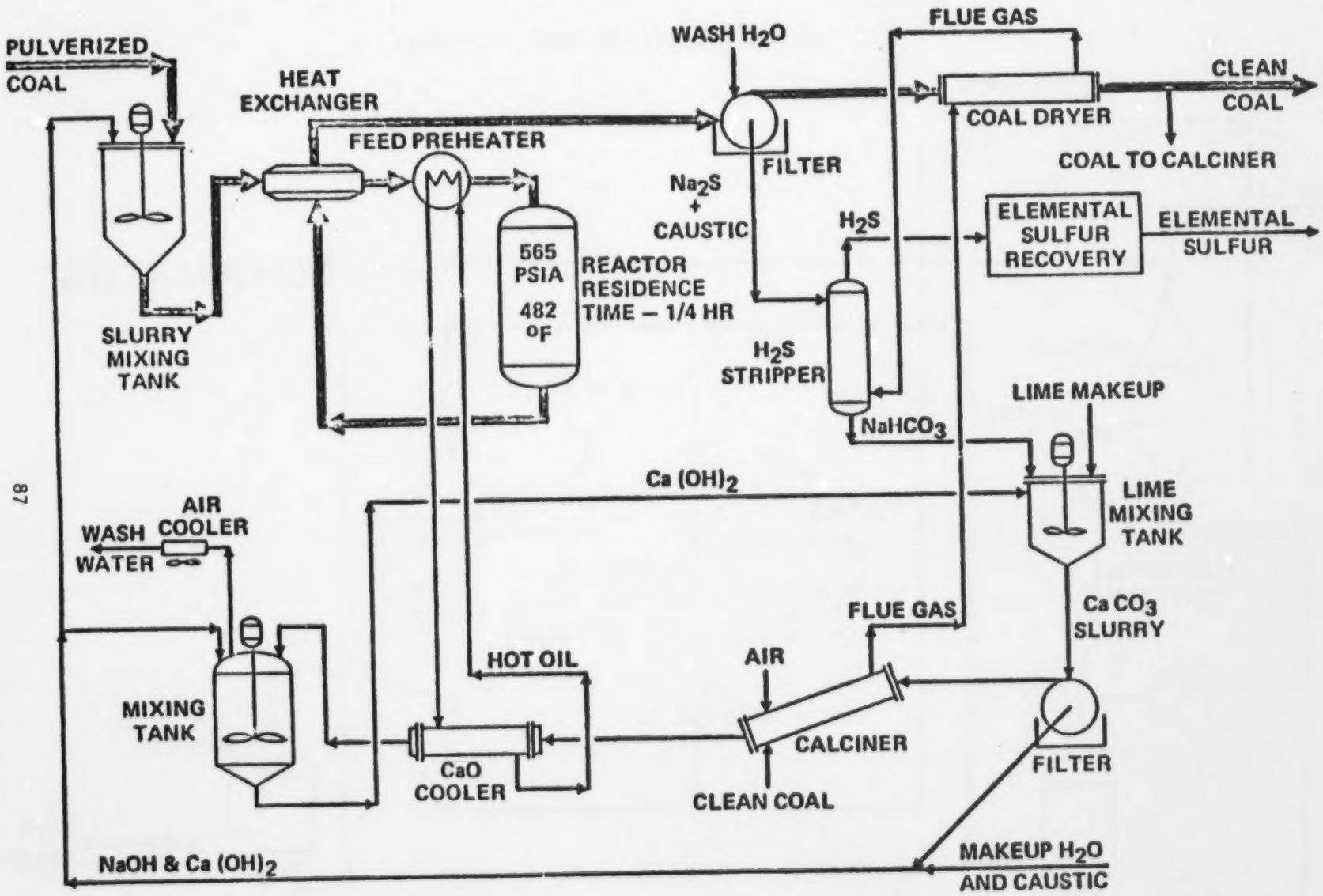


FIGURE 27. BATTELLE HYDROTHERMAL PROCESS FLOW DIAGRAM

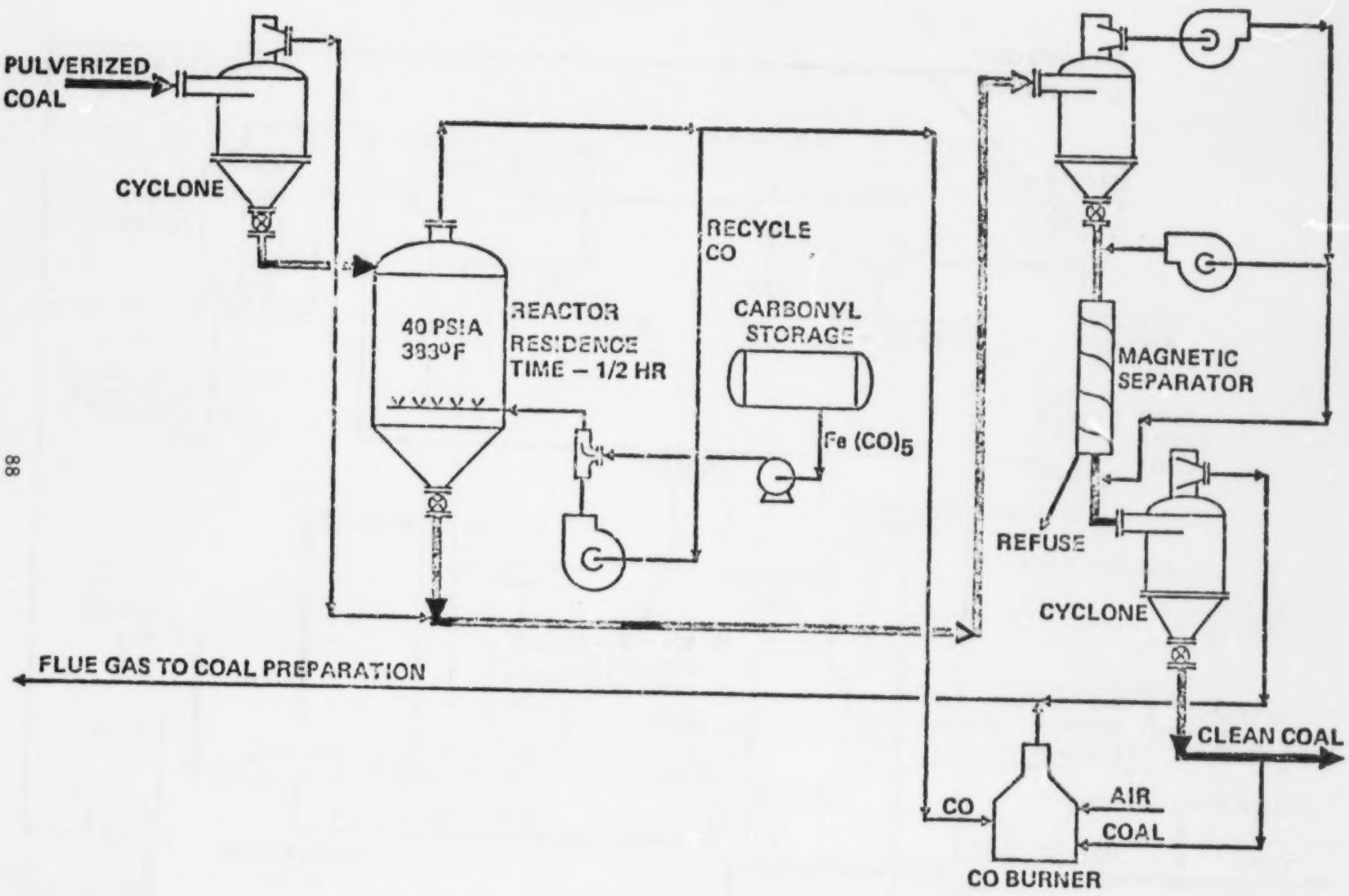


FIGURE 28. HAZEN PROCESS FLOW DIAGRAM

The $Fe_2S_3$ is much more magnetically susceptible enabling it to be magnetically separated from the coal. Thus this process can remove only mineral sulfur, and requires very fine grinding of the coal in order to liberate the pyrite particles. This may restrict application of the Hazen process. The process is simpler than others, using fewer unit operations and process steps, at mild temperatures and pressures. The process does have severe process monitoring requirements due to the use of highly toxic iron pentacarbonyl.

Results reported to date have been limited to coal ground to 1.19 mm (14 mesh) because there are no magnetic separators available to handle dry, fine-pulverized materials. This will hinder development of the process.

Bechtel[4] has estimated costs for a 300 kkg (330 short ton) per hour plant for a Pittsburgh bituminous coal as a capital cost of $48 million, and operating and maintenance costs of about $15.40 per kkg ($14 per short ton) cleaned. They indicate a cleaning cost of $.57 per GJ ($.60 per million Btu), with a Btu recovery of 76 percent. There are few aspects of Bechtel's design that are specified. One specified is the $Fe(CO)_5$ cost. Hazen estimates its cost at $.10 per pound with a consumption of 32 pounds per ton of coal (whether ROM or cleaned is not specified). Private vendor prices for $Fe(CO)_5$ go as high as $3.30 per kkg ($1.50 per pound). This higher price would change the cleaning costs dramatically.

Along with monitoring $Fe(CO)_5$ levels in the plant area, the disposal of the refuse will be of environmental concern. Problems involved will be very much the same as those for refuse from physical cleaning, except that Hazen refuse, because of its small particle size, will create severe dusting problems.

Hazen is considering a 0.9 kkg (1 ton) per day plant, so commercialization might be in 6 to 8 years.

KVB. The KVB process[4,5], shown in Figure 29, oxidizes sulfur components of dry pulverized -1.19 mm + 0.595 mm (-14 + 28 mesh) coal with $NO_2$ followed by caustic leaching to solubilize and remove the sulfur compounds formed in the oxidation step. The soluble sulfur compounds are mixed with lime to regenerate caustic and precipitate gypsum ($CaSO_4$), and iron oxides, which would be landfilled. The advantages of the KVB process are its claim to removal of both mineral and organic sulfur (up to 63 percent sulfur removal with oxidation, 87 percent with additional caustic leaching), the simplicity and low costs of dry oxidation, and the moderate temperatures,

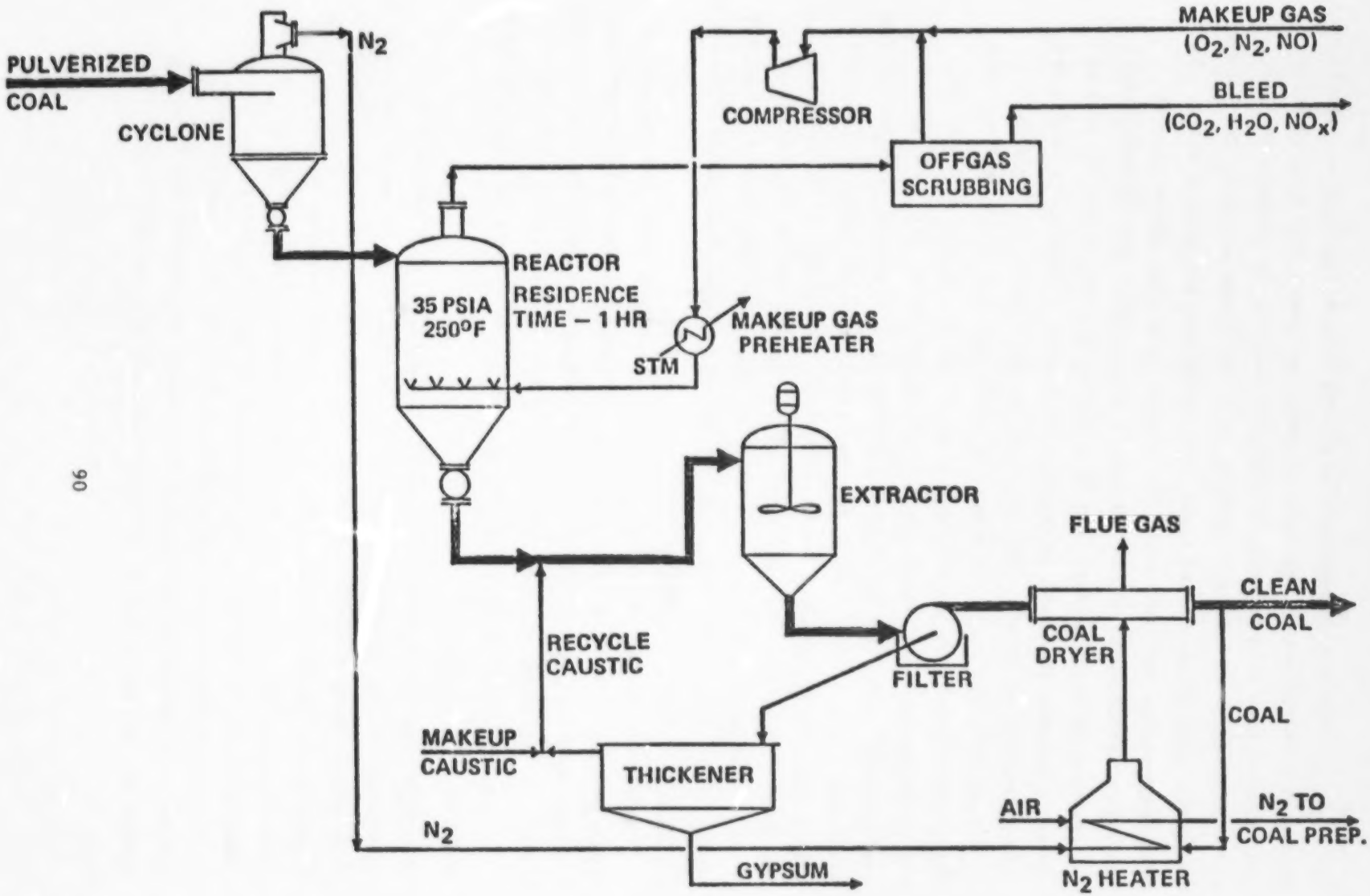


FIGURE 29. KVB PROCESS FLOW DIAGRAM

pressures, and vessel residence times. A problem in the system is the uptake of nitrogen by the coal.

Bechtel has developed cost information on the KVB process, based on the KVB patent and limited nonproprietary information (no literature is available and little bench scale work has been done). Bechtel indicates a capital cost of $68 million for a 300 kkg (330 short tons) per hour plant with an operating and maintenance cost of $25 per kkg of cleaned coal ($23 per cleaned short ton). They indicate a cost of $.93 per GJ ($.98 per million Btu), for a Pittsburgh bituminous coal, with 90 percent Btu recovery.

Environmentally, the KVB process has one major problem; it is a $NO_x$ producer. No information is available on expected effluent levels of $NO_x$. The other waste product is gypsum for which established disposal technologies are available.

Ledgemont Oxygen Leaching. This process[4,5] (LOL) (see Figure 30) is based on the following reaction.

$$FeS_2 + H_2O + 3.5O_2 \rightarrow FeSO_4 + H_2SO_4 \quad .$$

High temperatures and pressures must be used to speed the reaction rate for a commercially viable process. Strong oxidizing conditions in the reactor cause some coal loss and volatization in the reactor. This results in loss of heating value. The process has no significant organic sulfur removal capability. Sulfur is removed from the system by mixing the reaction products with lime, producing gypsum and iron oxides which would be landfilled. Kennecott Copper Company claims 95 percent pyritic sulfur removal in the LOL process, with 93 percent Btu recovery.

Dynatech and Bechtel[4,5] have studied the economics of the LOL process. Dynatech's study gives an operating cost of $7.60 per kkg ($6.90 per short ton) cleaned, but no capital costs. Bechtel's study gives a capital cost of $155 million for a 300 kkg (330 short tons) per hour plant with an operating cost of $20.90 per kkg ($19 per cleaned short ton) or $0.77 per GJ ($0.81 per million Btu). Dynatech does not indicate what coals were used as a design base, or what type of preparation facilities were included in the cost case. Bechtel indicates a Pittsburgh A bituminous coal pulverized to 80 percent minus 74 μm (200 mesh).

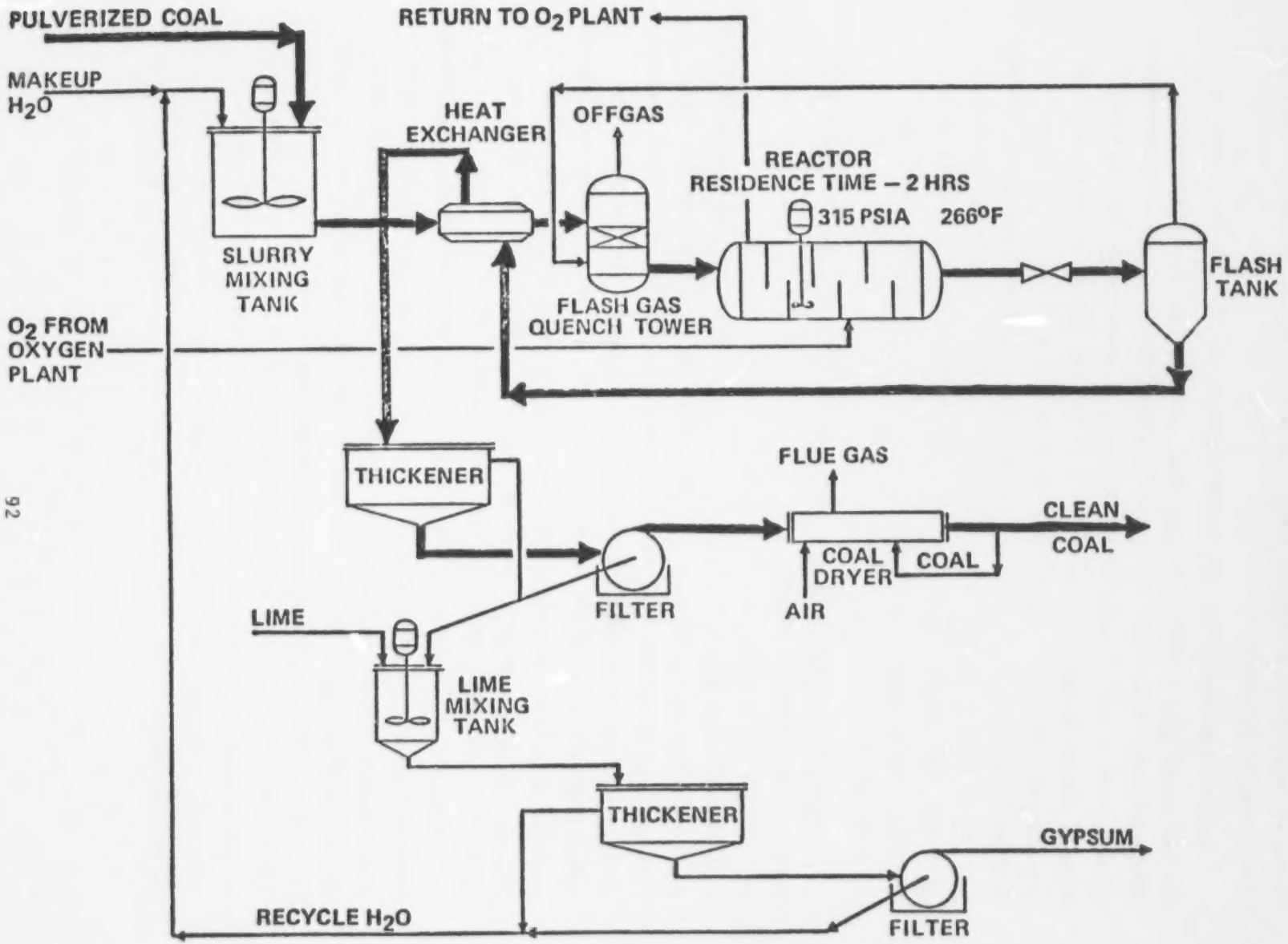


FIGURE 30. LOL PROCESS FLOW DIAGRAM

BOM/ERDA. This process[4] (see Figure 31) uses wet oxidation, employing air instead of oxygen as used by LOL. The BOM/ERDA process operates at higher temperatures and pressures than LOL, generating iron sulfates and sulfuric acid. Because of the extreme operating conditions, both pyritic and organic sulfur removal are claimed, and the process can be expected to show coal loss similar to the LOL process. Lime is used to convert iron sulfates to iron oxides and gypsum.

Bechtel[4] has studied the economics of this process using a Pittsburgh bituminous coal. With pulverization facilities, grinding to 80 percent minus 74 μm (200 mesh), Bechtel estimates a capital cost of $130 million and an operating and maintenance cost of $20.90 per kkg of cleaned coal ($19 per cleaned short ton), or $.80 per GJ ($.84 per million Btu) with a Btu recovery of 94 percent. These costs are for a 300 kkg (330 short tons) per hour plant.

Environmentally, the BOM/ERDA process will be very similar to the LOL process. The process is under bench scale development, so commercialization would be about 6 to 9 years off.

Dynatech. This process[5] uses microbial action at 38 C (100 F) and 1 atmosphere pressure. There is little information, but Dynatech does indicate using minus 74 μm (200 mesh) washed coal, complete pyritic and some organic (amount unknown) removal, and gypsum, sulfuric acid, and elemental sulfur products. Dynatech has released limited cost data for a 300 kkg (330 ton) per hour plant with coal preparation facilities, indicating a cost of $4.15 per kkg ($4.05 per ton) of cleaned coal. Other details are not available.

General Electric. GE is developing a process[5] that radiates coal with microwaves, gasifying the sulfur. Information is limited, but GE claims 52 percent reduction in pyritic and organic sulfur, and the possibility of reducing sulfur in most coals to 0.7 percent. Products of the process are $H_2S$, COS, $SO_2$, $H_2O$, $CO_2$, and traces of $CH_4$, $C_2H_6$, and $H_2$. GE's preliminary cost data for a 440 kkg (400 ton) per hour plant claims a cost of $7.30 per kkg of cleaned coal ($6.60 per cleaned ton).

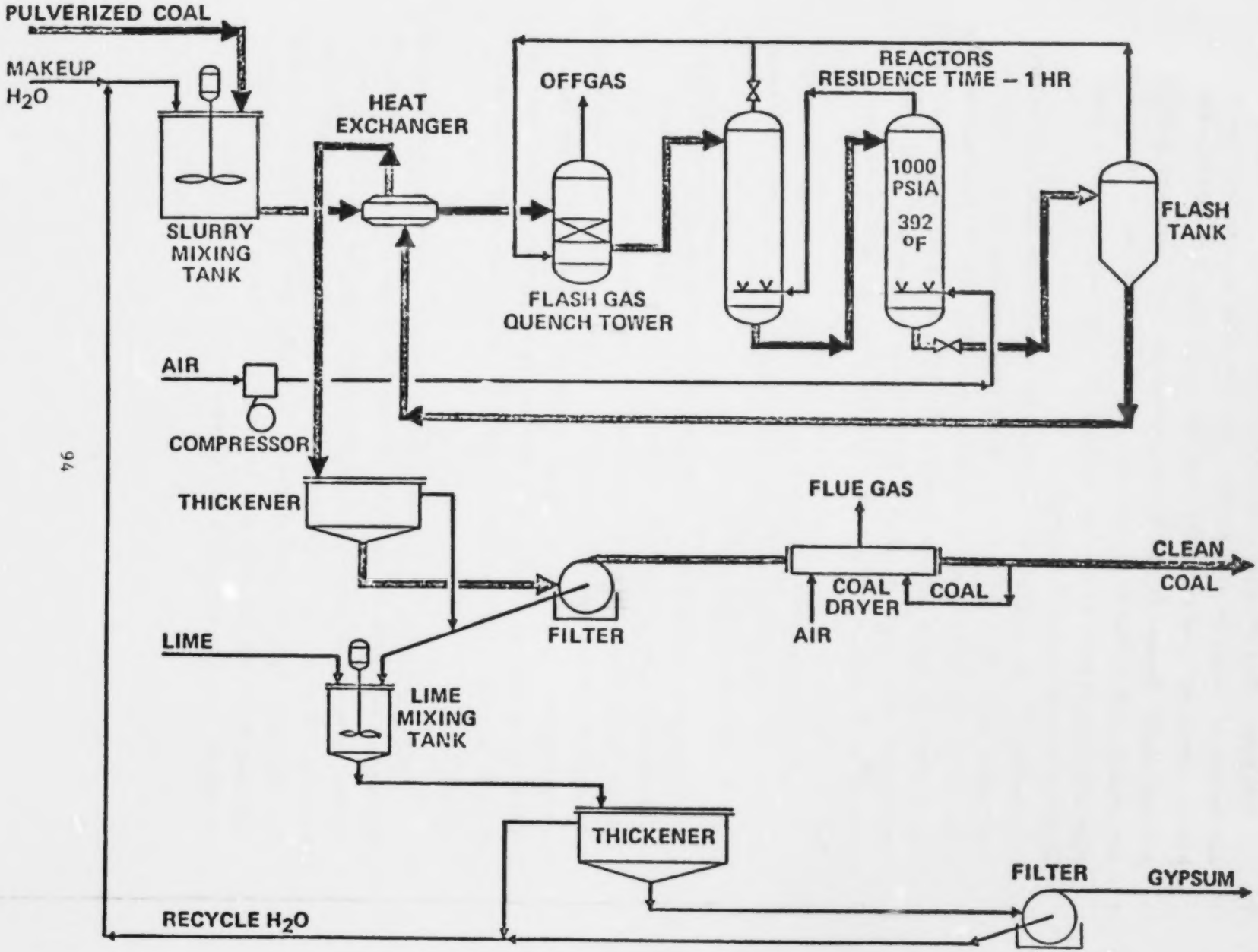


FIGURE 31. BOM/ERDA PROCESS FLOW DIAGRAM

Summary of Coal Cleaning Costs. A summary of the costs of various coal cleaning processes is given in Table 24, together with the ranges of sulfur removal and Btu recovery claimed for each process.

TABLE 24. MAJOR COAL CLEANING PROCESS CONSIDERATIONS

| PROCESS | PLANT SIZE BASIS short ton per hour | COSTS CAPITAL $10^6$ | COSTS PROCESSING(b) $/ton | COSTS PROCESSING(b) $/$10^6$ Btu | SULFUR REMOVAL PYRITIC % | SULFUR REMOVAL ORGANIC % | BTU RECOVERY % |
|---|---|---|---|---|---|---|---|
| Physical(a) | 500 | 9.0 | 4.27 | .18 | 35-70 | - | 80-95 |
| TRW/Meyers(a) | 380 | 145 | 10.- 14. | .82 | 95 | - | 90 |
| Battelle Hydro-thermal | 400 | 134.-145. | 18.-25. | 1.00 | 99 | 24-72 | 75-90 |
| Hazen | 330 | 48. | 14. | .60 | 80 | - | 76 |
| KVB | 330 | 68. | 23. | .98 | 99 | 13 | 90 |
| LOL | 330 | 150. | 19. | .81 | 95 | - | 93 |
| BOM/ERDA | 330 | 130. | 19. | .84 | 99 | 15 | 94 |
| Dynatech | 330 | - | 4.05 | - | - | - | - |
| GE | 400 | - | 6.60 | - | 50 (Combined) | | - |

(a) See text for basis of costs and other data.

(b) Includes capital charge plus operating and maintenance costs, basis for costs are cleaned coal.

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